

Utility-Scale Solar

Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States

2018 Edition

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September 2018

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 **SOLAR ENERGY
TECHNOLOGIES OFFICE**
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Presentation Outline

Strong growth of the utility-scale solar market provides increasing amounts of empirical project-level data that are ripe for analysis

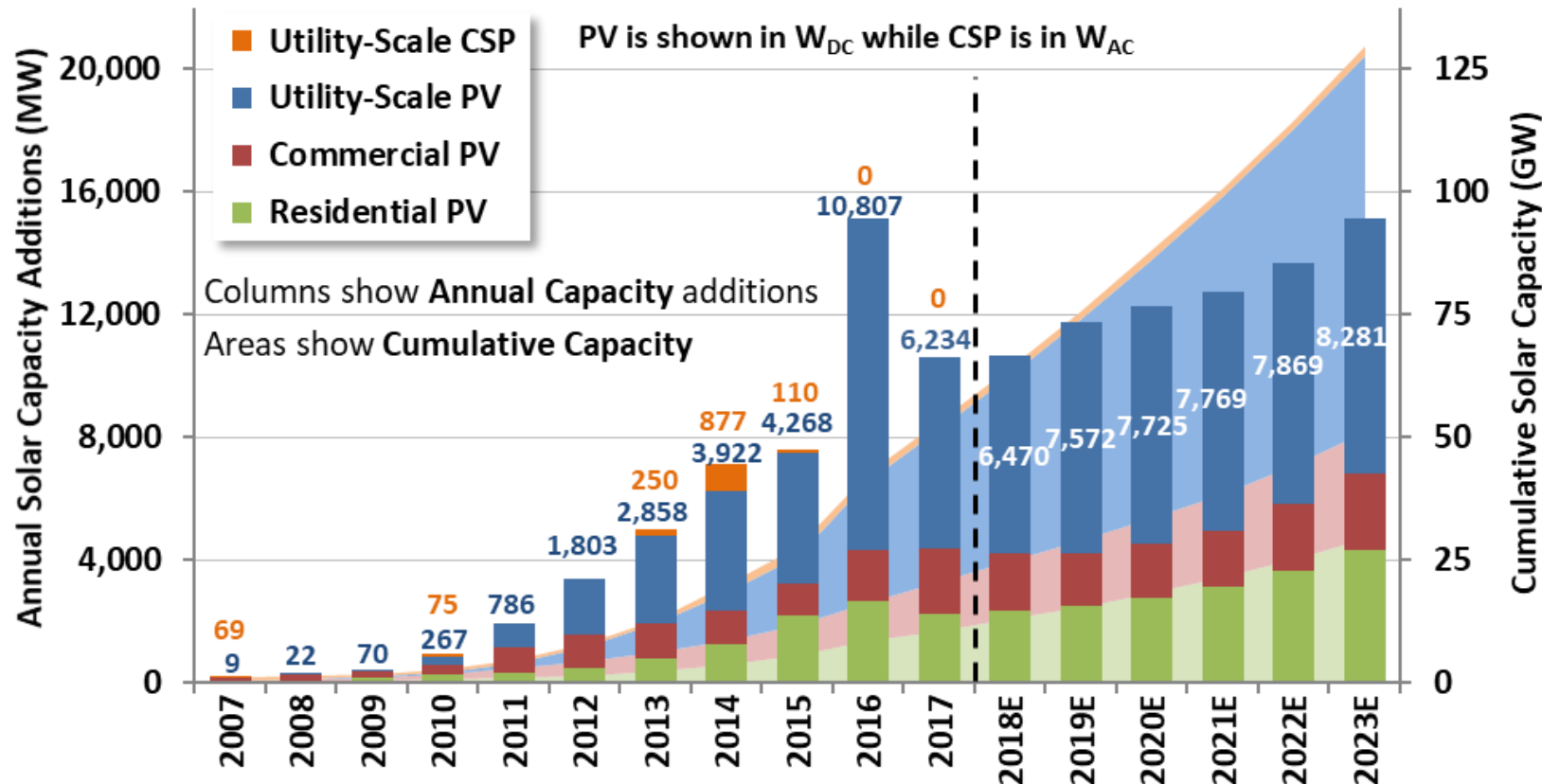
1. Solar deployment trends (and utility-scale's relative contribution)

Key findings from analysis of the data samples (*first for PV, then for CSP*):

2. Project design, technology, and location
3. Installed project prices
4. Operation and maintenance (O&M) costs
5. Performance (capacity factors)
6. Power purchase agreement ("PPA") prices

7. Future outlook

Utility-scale projects have the greatest capacity share in the U. S. solar market



Sources: GTM/SEIA Solar Market Insight Reports, Berkeley Lab

The utility-scale sector accounted for 6.2 GW_{DC} or **59% of all new** solar capacity added in 2017 and **60% of cumulative** solar capacity at the end of 2017.

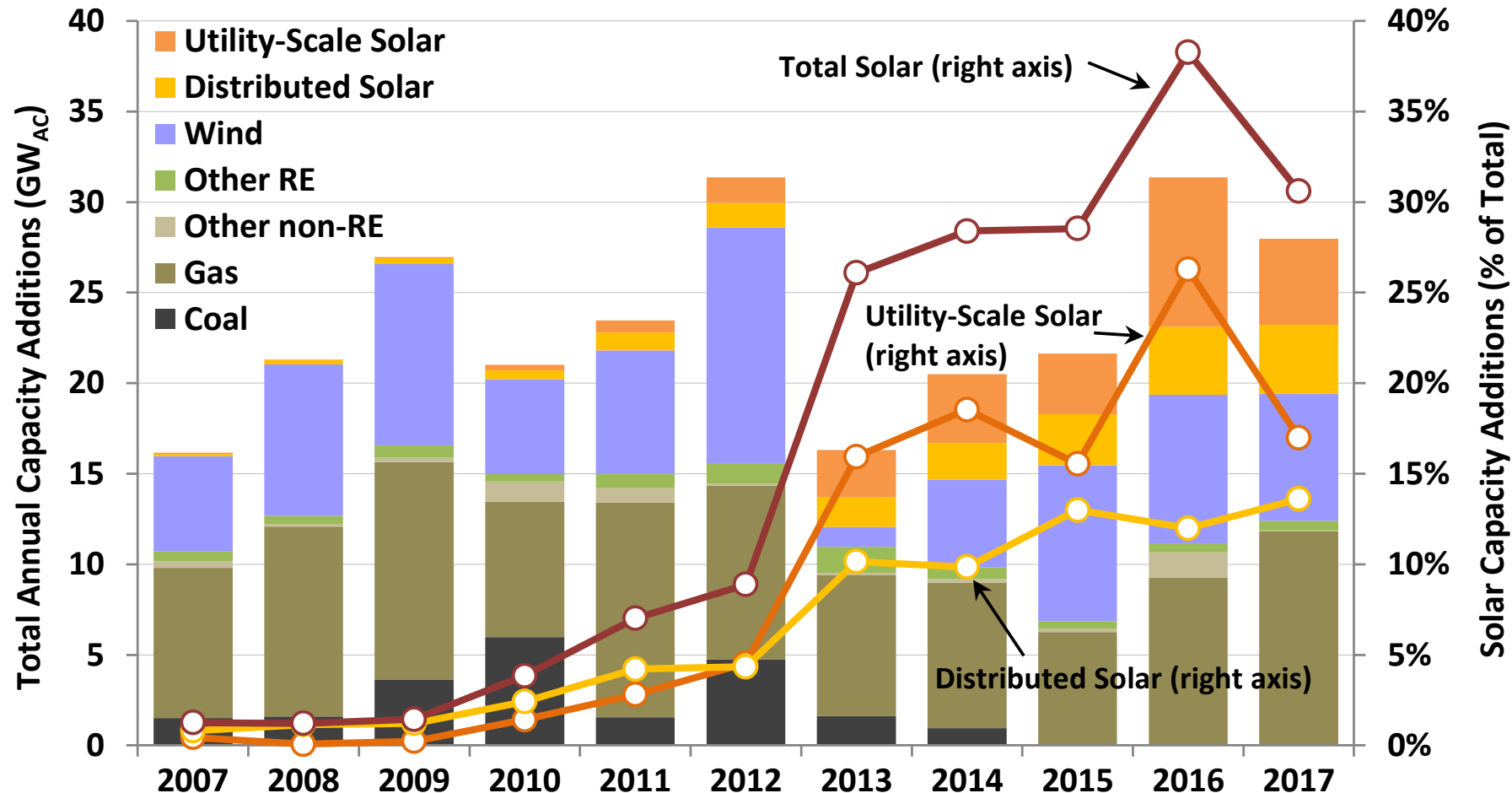
Capacity additions declined in comparison to 2016's record year (driven by then-planned ITC phase-out) but were still 46% above 2015.

Our data sample analyzes all projects larger than 5 MW_{AC} that were completed by the end of 2017:

- **2016:** 162 new projects totaling 7.5 GW_{AC} (9.8 GW_{DC})
- **2017:** 146 new projects totaling 3.9 GW_{AC} (5.2 GW_{DC})

We define "utility-scale" as any ground-mounted project that is larger than 5 MW_{AC} .
Smaller systems are analyzed in LBNL's "Tracking the Sun" series (trackingthesun.lbl.gov)

Solar power was the second largest source of U.S. electricity-generating capacity additions in 2017



Led by the utility-scale sector, solar power has comprised >25% of all generating capacity additions in the United States in each of the past five years.

In 2017, solar made up 31% of all U.S. capacity additions (with utility-scale accounting for 17%), ahead of wind (25%) but behind natural gas (42%).

Sources: ABB, AWEA, GTM/SEIA Solar Market Insight Reports, Berkeley Lab

Note: This graph follows GTM/SEIA's split between distributed and utility-scale solar, rather than our 5 MW_{AC} threshold

Solar penetration rates top 15% in California and exceed 10% in several other states

State	PV generation as a % of in-state generation		PV generation as a % of in-state load	
	All PV	Utility-Scale PV Only	All PV	Utility-Scale PV Only
California	15.2%	10.1%	12.3%	8.1%
Hawaii	11.8%	2.0%	12.5%	2.1%
Vermont	11.5%	6.2%	4.4%	2.4%
Nevada	10.7%	9.7%	11.1%	10.0%
Massachusetts	8.1%	3.3%	4.3%	1.8%
Utah	6.2%	5.4%	7.5%	6.5%
Arizona	5.5%	3.8%	7.4%	5.2%
North Carolina	4.4%	4.3%	4.4%	4.3%
New Mexico	3.9%	3.3%	5.7%	4.8%
New Jersey	3.8%	1.6%	3.9%	1.6%
Rest of U.S.	0.5%	0.3%	0.6%	0.3%
TOTAL U.S.	1.8%	1.2%	2.0%	1.3%

Source: EIA's Electric Power Monthly (February 2018)

Note: In this table, "utility-scale" refers to projects $\geq 1 \text{ MW}_{AC}$, rather than our typical 5 MW_{AC} threshold.

Solar penetration rate varies considerably depending on whether it is calculated as a percentage of generation or load (e.g., see Vermont).

In 2017, seven states achieved solar penetration levels $>5\%$ based on generation share. Six states had $>5\%$ based on load share.

Contribution of utility-scale also varies (a minority in northeast states and Hawaii, a majority in other states and overall).

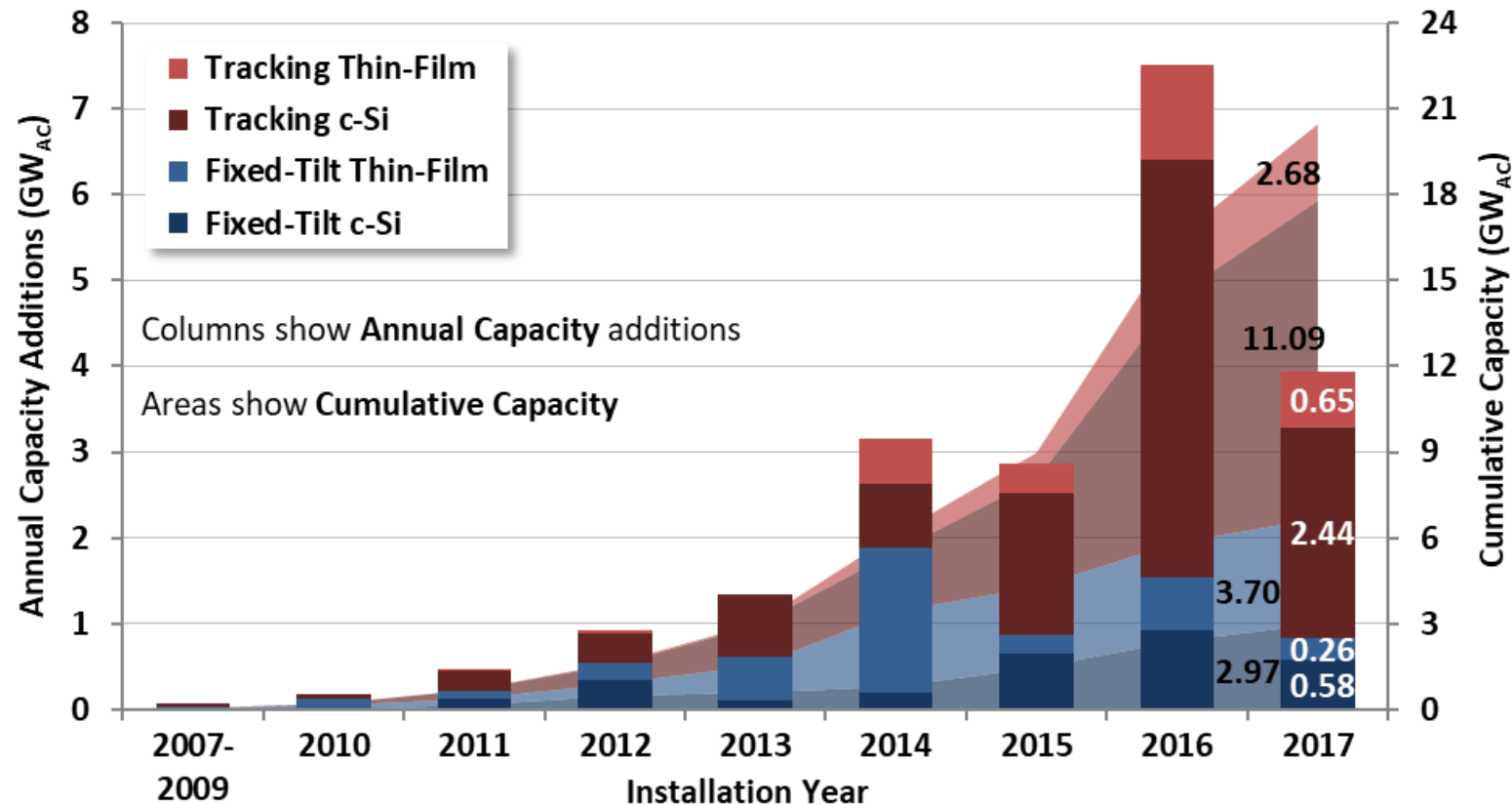
Utility-Scale Photovoltaics (PV)



Photo Credit: East Pecos Solar 120MW_{AC}, Texas, Southern Power

Projects with tracking technology dominated 2017 additions; c-Si modules led thin-film

PV project population: 590 projects totaling 20,515 MW_{AC}



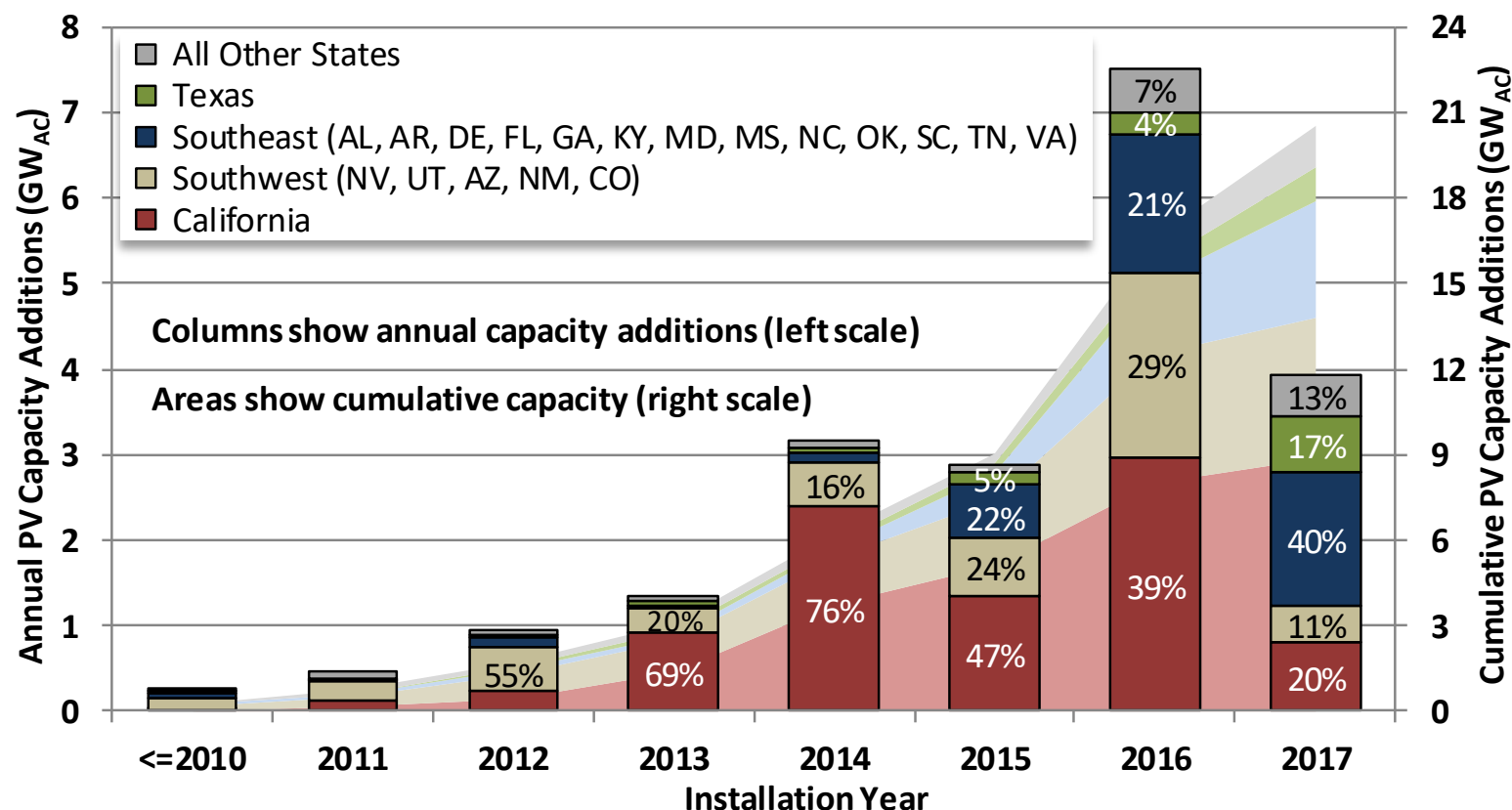
Continued dominance of **tracking** projects (79% of newly installed capacity or 72% of newly built projects) relative to **fixed-tilt** projects (21% or 28%). Preference for tracking now clearly visible for thin-film projects as well after years of module efficiency improvements.

c-Si modules continue their clear lead both in terms of newly installed capacity (77%) and newly installed projects (83%) relative to **thin-film** modules (23% or 17%).

Jinko Solar had the highest market share among c-Si modules in our sample, followed by Hanwha, Trina Solar, Canadian Solar, Mission Solar Energy and SunPower. First Solar provided nearly all thin-film (CdTe) modules in 2017.

The Southeast became the new national leader in solar growth

PV project population: 590 projects totaling 20,515 MW_{AC}



Strong growth outside California and the Southwest:

California's relative share of new additions has declined every year since 2014, but it's still the state with the most capacity growth in the nation (800 MW_{AC} or 20%).

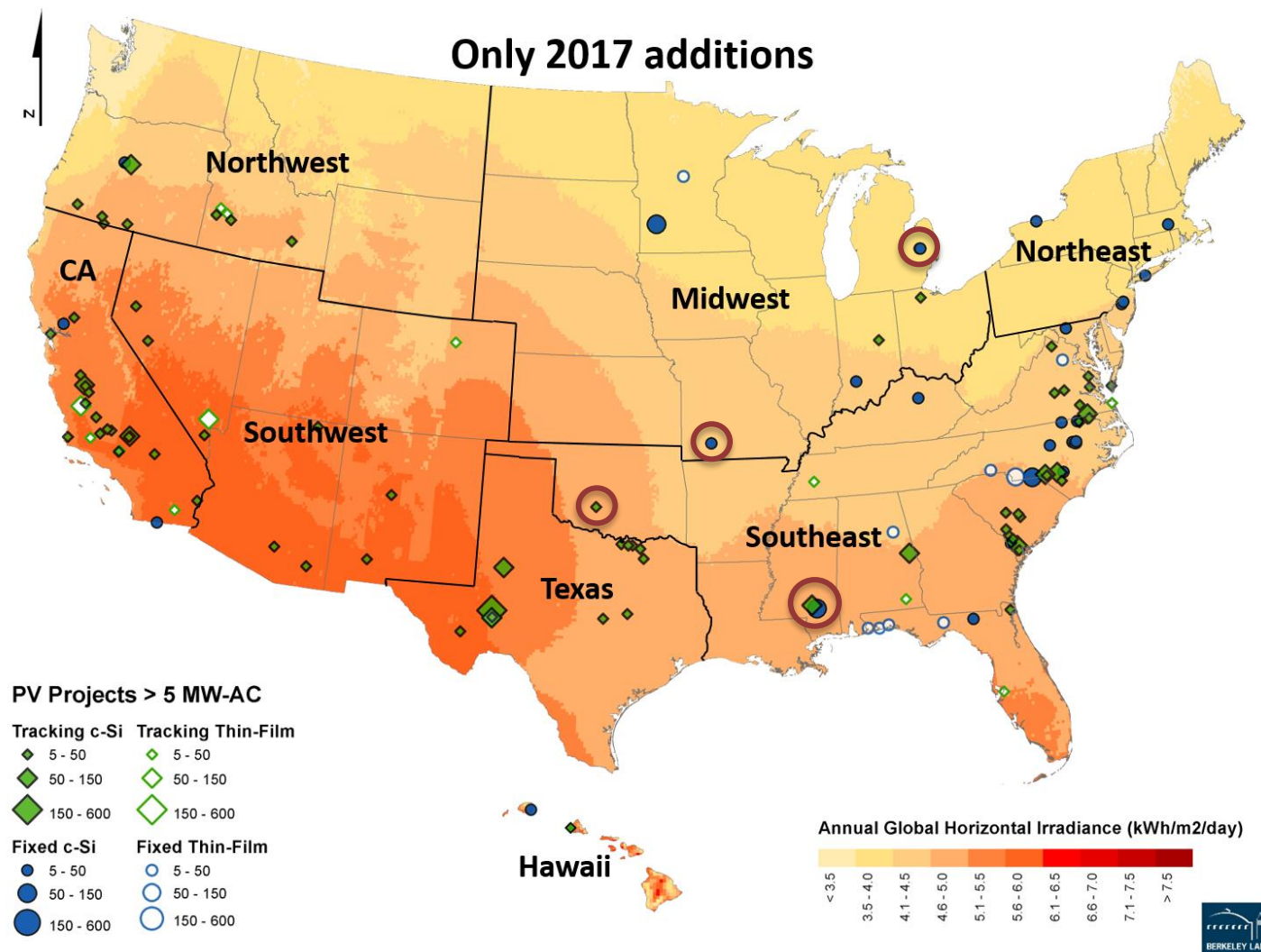
2017 is the first year in which areas **outside of California** and the **Southwest** accounted for the lion's share (70%) of new additions.

Texas added 651 MW_{AC} – the second-largest amount of new solar capacity among all states in 2017 and twice as much as in 2016.

North Carolina added 16% of all new additions with 20 projects in the 10-80MW_{AC} range, followed by **Virginia**, **South Carolina**, and **Florida**.

4 new states added their first utility-scale solar project: **Michigan**, **Missouri**, **Mississippi**, **Oklahoma**.

The Southeast became the new national leader in solar growth



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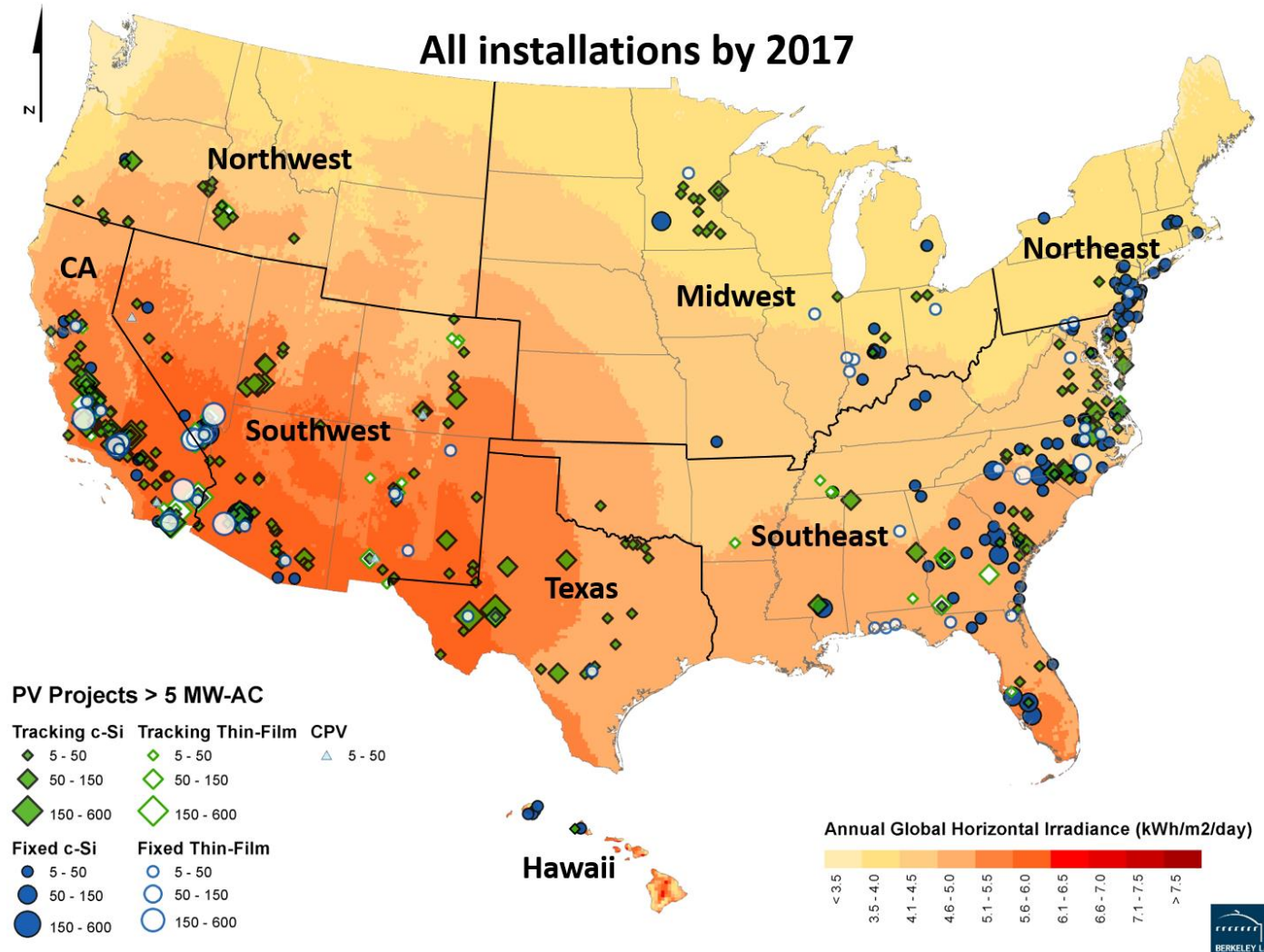
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Utility-Scale Solar has become a growing source of electricity in all regions of the United States

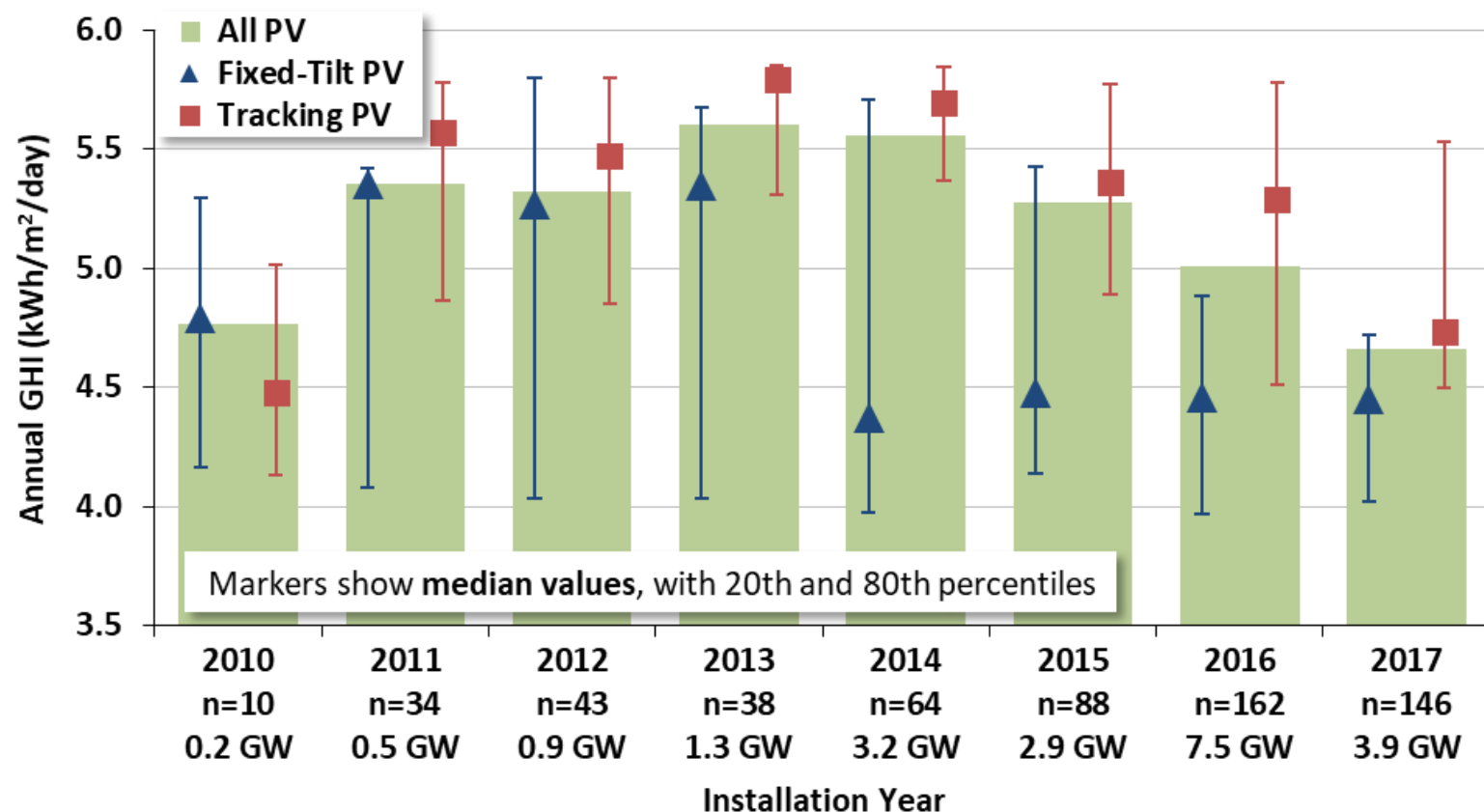


Utility-Scale PV is now well-represented throughout the nation with the exception of Midwestern states in the “wind belt.”

Fixed-tilt projects (in particular c-Si ●) have been built in lower-insolation regions, primarily along the east coast.

Tracking projects (◆) started out in the Southwest but have increasingly spread throughout the country, north to Oregon, Idaho, and Minnesota, and east to Virginia. Hawaii added its first tracking project in 2017.

Utility-Scale Solar is increasingly built at lower-insolation sites

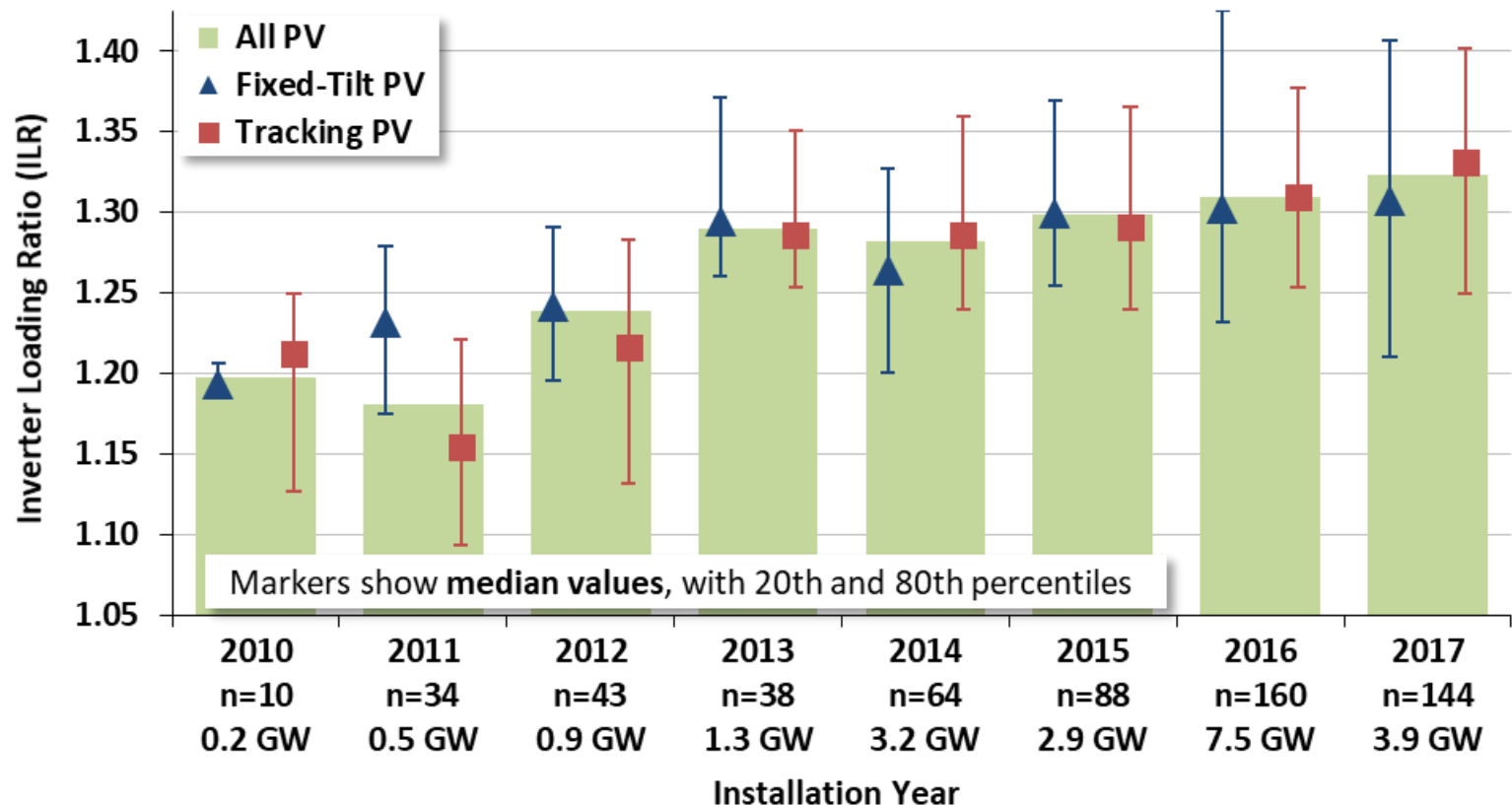


The median solar resource (measured in long-term global horizontal irradiance—**GHI**) at new project sites has decreased since 2013 as the market expands to less-sunny states.

Fixed-tilt PV is increasingly relegated to lower-insolation sites (note the decline in its **80th percentile**), while tracking PV is pushing into those same areas (note the decline in its **20th percentile**).

All else equal, the buildout of lower-GHI sites will dampen sample-wide capacity factors (reported later).

The median inverter loading ratio (ILR) continued to climb



As module prices have fallen (faster than inverter prices), developers have oversized the DC array capacity relative to the AC inverter capacity to enhance revenue and reduce output variability.

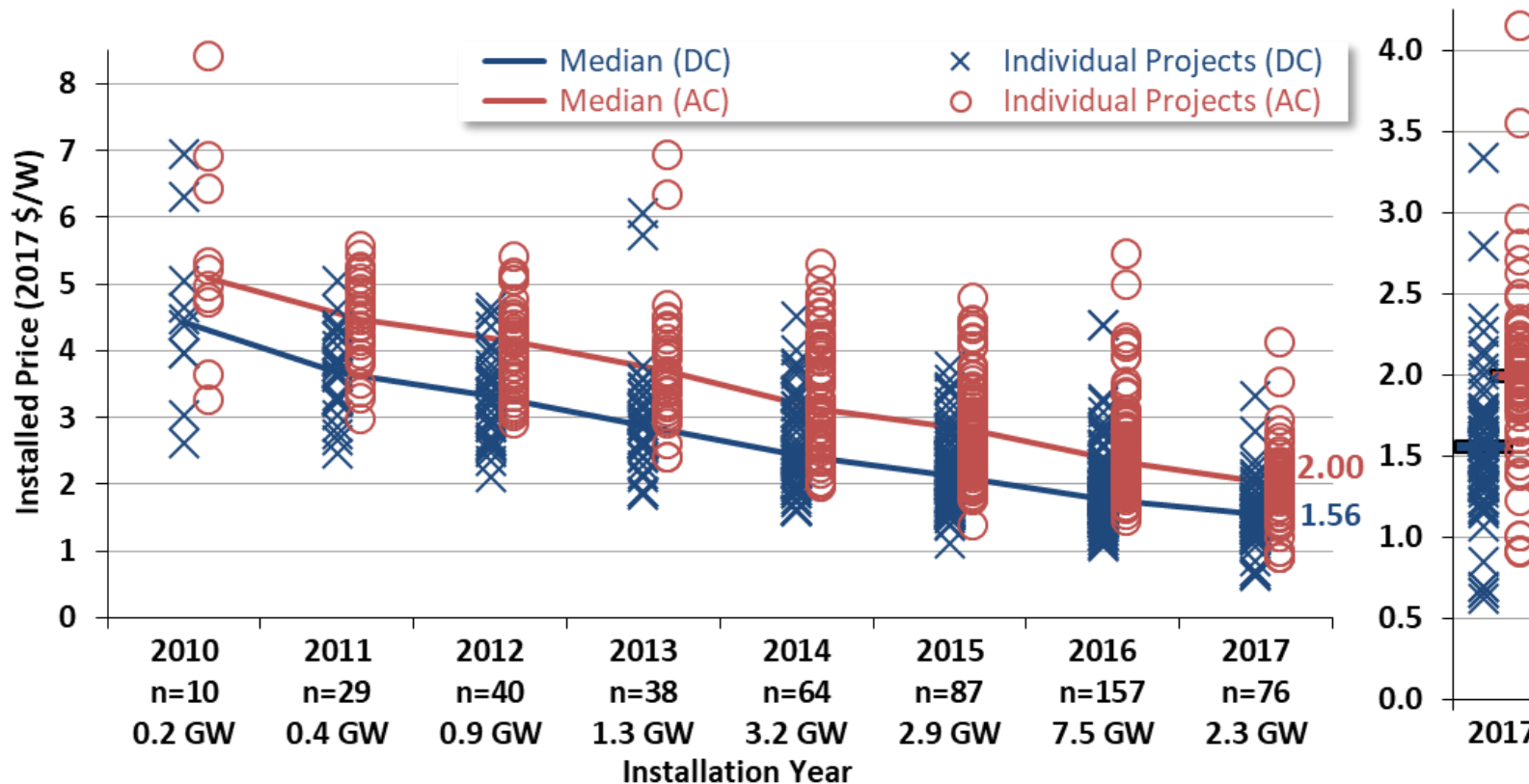
The median inverter loading ratio (**ILR** or DC:AC ratio) increased to 1.32 in 2017, though considerable variation remains (ranging from 1.06 to 1.61).

Fixed-tilt PV has more to gain from a higher ILR than does tracking PV, and historically has had a higher ILR. In recent years, though, tracking has outpaced fixed-tilt in terms of median ILR (1.33 vs. 1.31 in 2017).

All else equal, a higher ILR should boost capacity factors (reported later).

Median installed price of PV has fallen by more than 60% since 2010, to \$2.0/W_{AC} (\$1.6/W_{DC}) in 2017

PV price sample: 506 projects totaling 18,745 MW_{AC}



The lowest 20th percentile of project prices fell from \$2.0/W_{AC} (\$1.5/W_{DC}) in 2016 to \$1.8/W_{AC} (\$1.3/W_{DC}) in 2017.

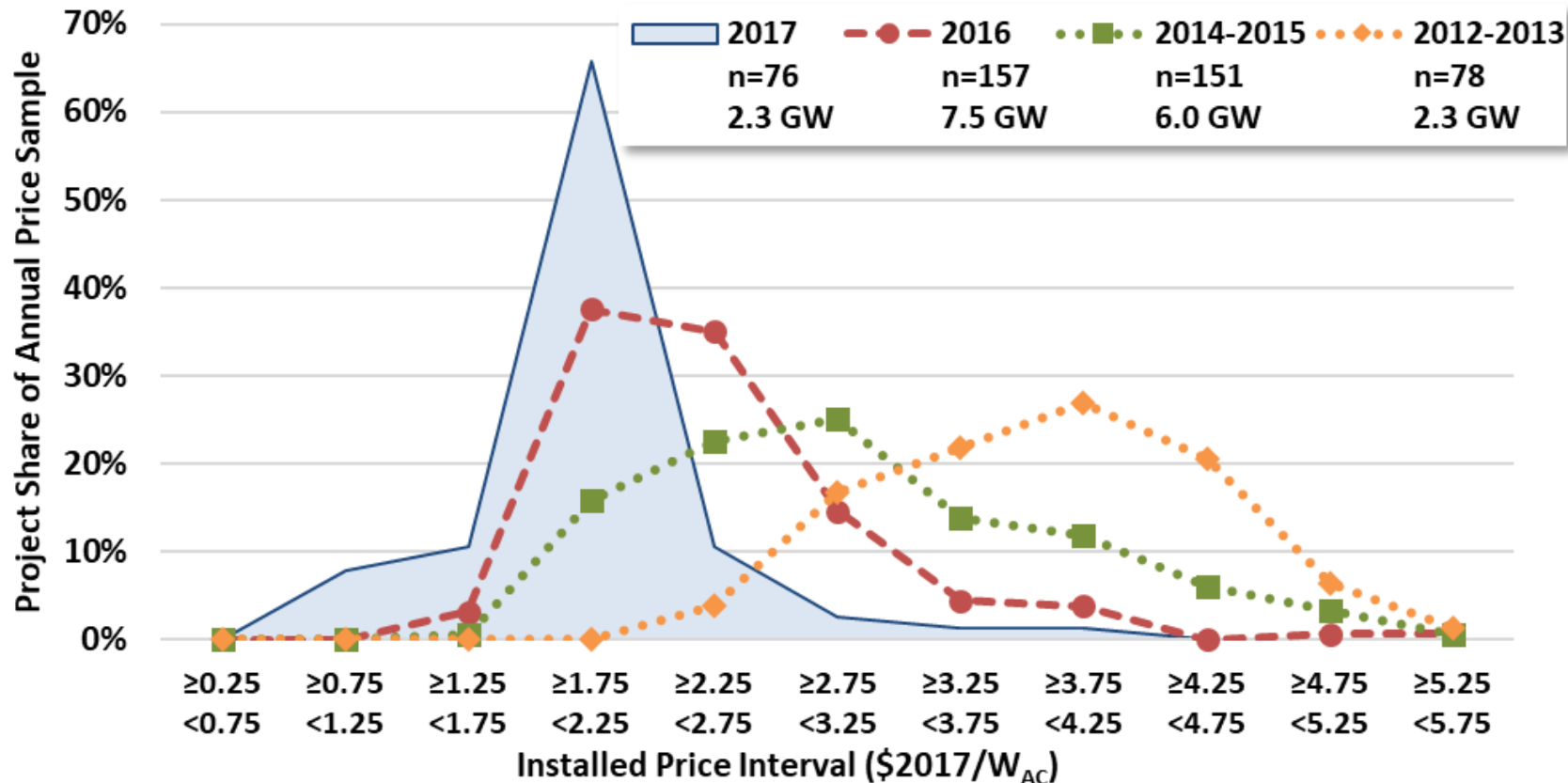
The lowest projects among the 67 data points in 2017 was \$0.9/W_{AC} (\$0.6/W_{DC}).

Historical pricing sample is very robust (91% of installed capacity). 2017 data covers 52% of new projects or 58% of new capacity.

This sample is backward-looking and does not reflect the price of projects built in 2018/2019.

Pricing distributions have narrowed and continuously moved towards lower prices over the last 6 years

PV price sample: 506 projects totaling 18,745 MW_{AC}



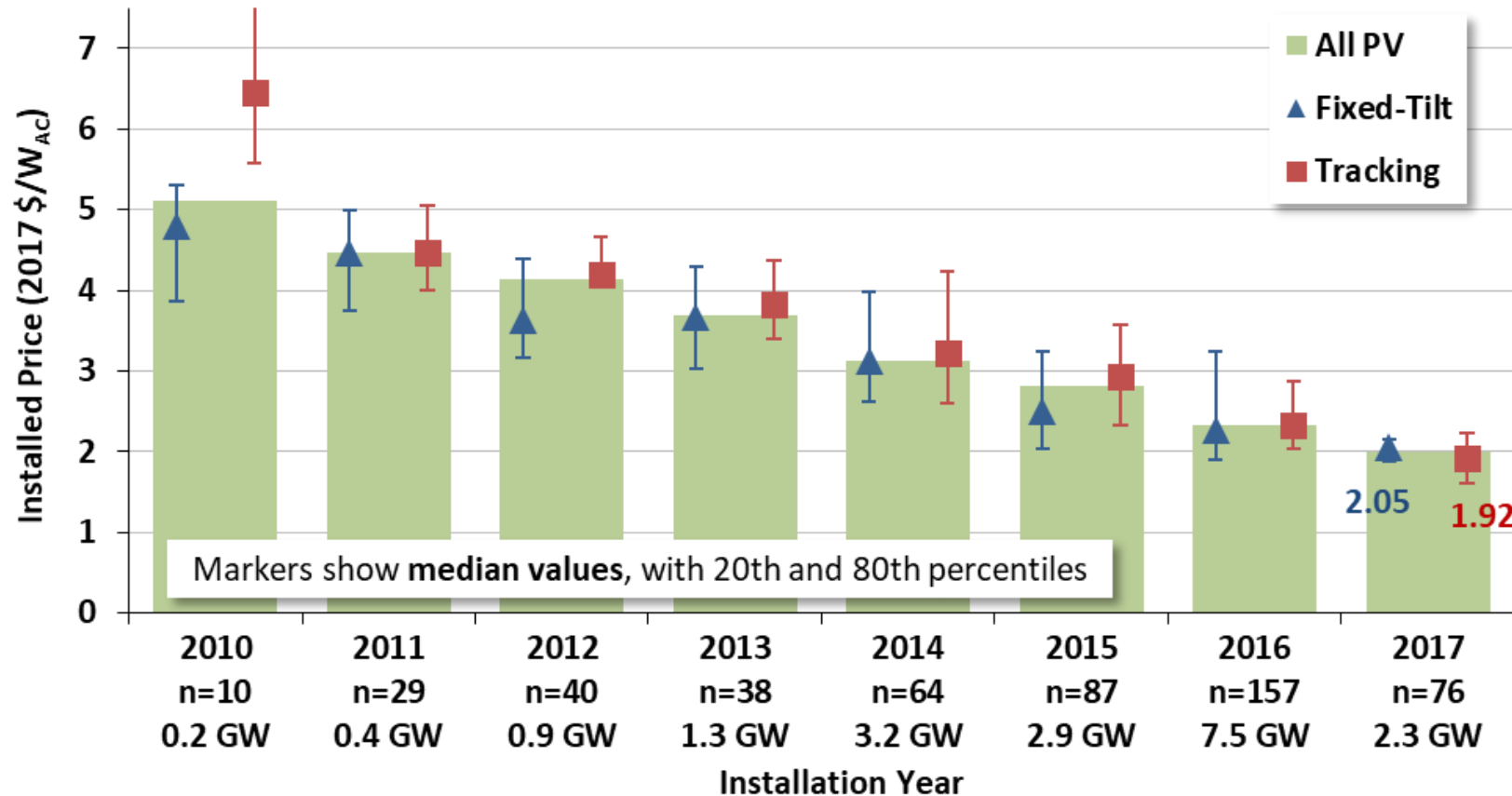
Both medians and modes have continued to fall (i.e., shift towards the left) each year.

Share of relatively high-cost systems decreases steadily each year while share of low-cost systems increases.

Price spread is the smallest in 2017, pointing to a reduction in underlying heterogeneity of prices across all installed projects.

Historical cost premium of tracking over fixed-tilt installations has seemingly disappeared in 2017

PV price sample: 506 projects totaling 18,745 MW_{AC}



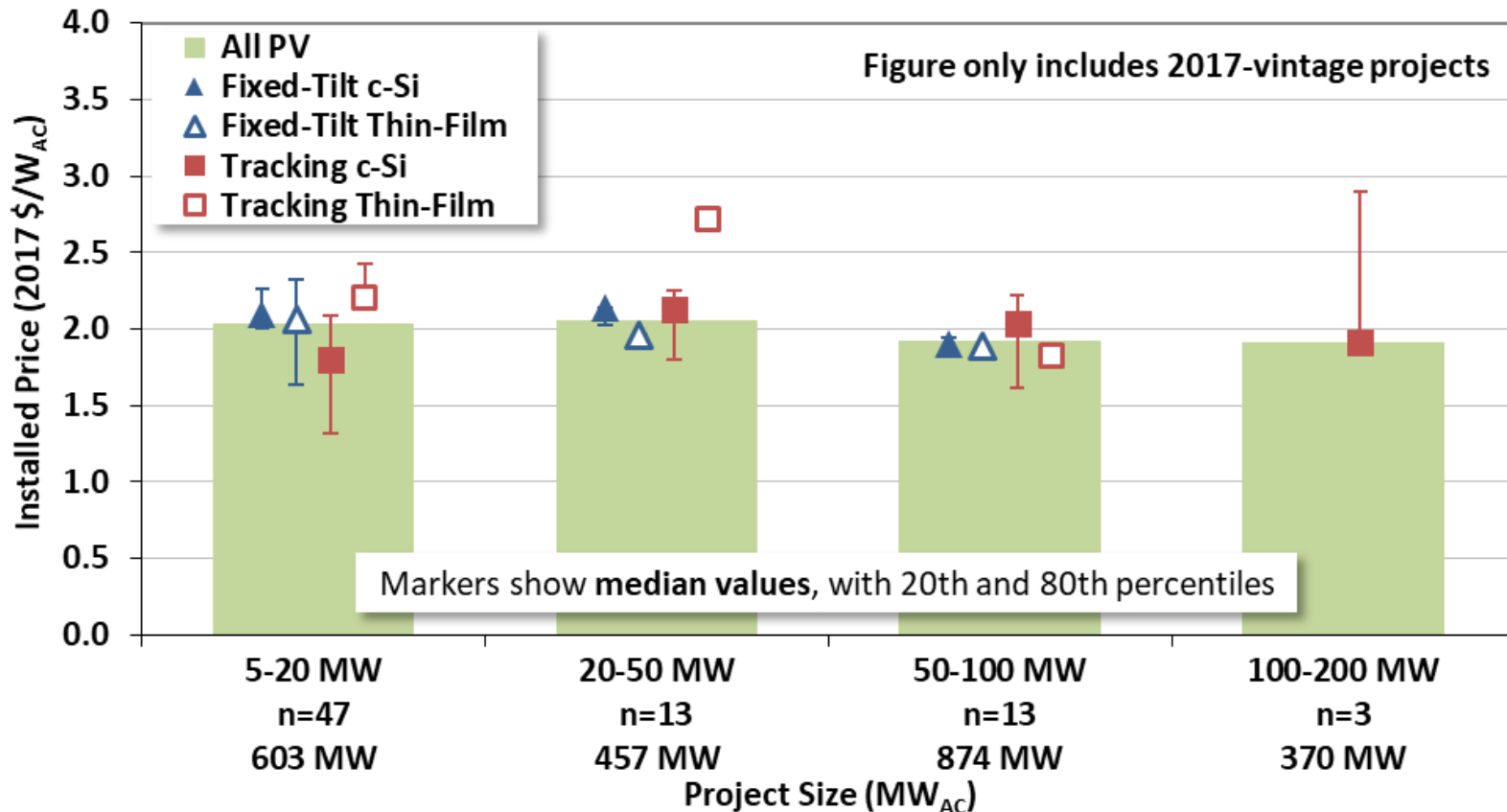
Tracking's empirical cost premium has varied somewhat over time, but had declined to just \$0.1/W_{AC} in 2016.

2017 is the first year in which the premium has apparently *reversed* to \$2.0/W_{AC} (\$1.6/W_{DC}) for fixed-tilt projects vs. \$1.9/W_{AC} (\$1.5/W_{DC}) for tracking projects. This is likely just a sampling issue or driven by other underlying cost drivers—i.e., for any given project, tracking likely still has a higher CapEx than fixed-tilt.

The historical upfront cost premium for trackers is usually compensated by higher annual generation.

Faint evidence of economies of scale among 2017 projects

PV price sample for 2017: 76 projects totaling 2,303 MW_{AC}



Differences in project size could potentially explain pricing variation – we focus only on 2017 for this analysis.

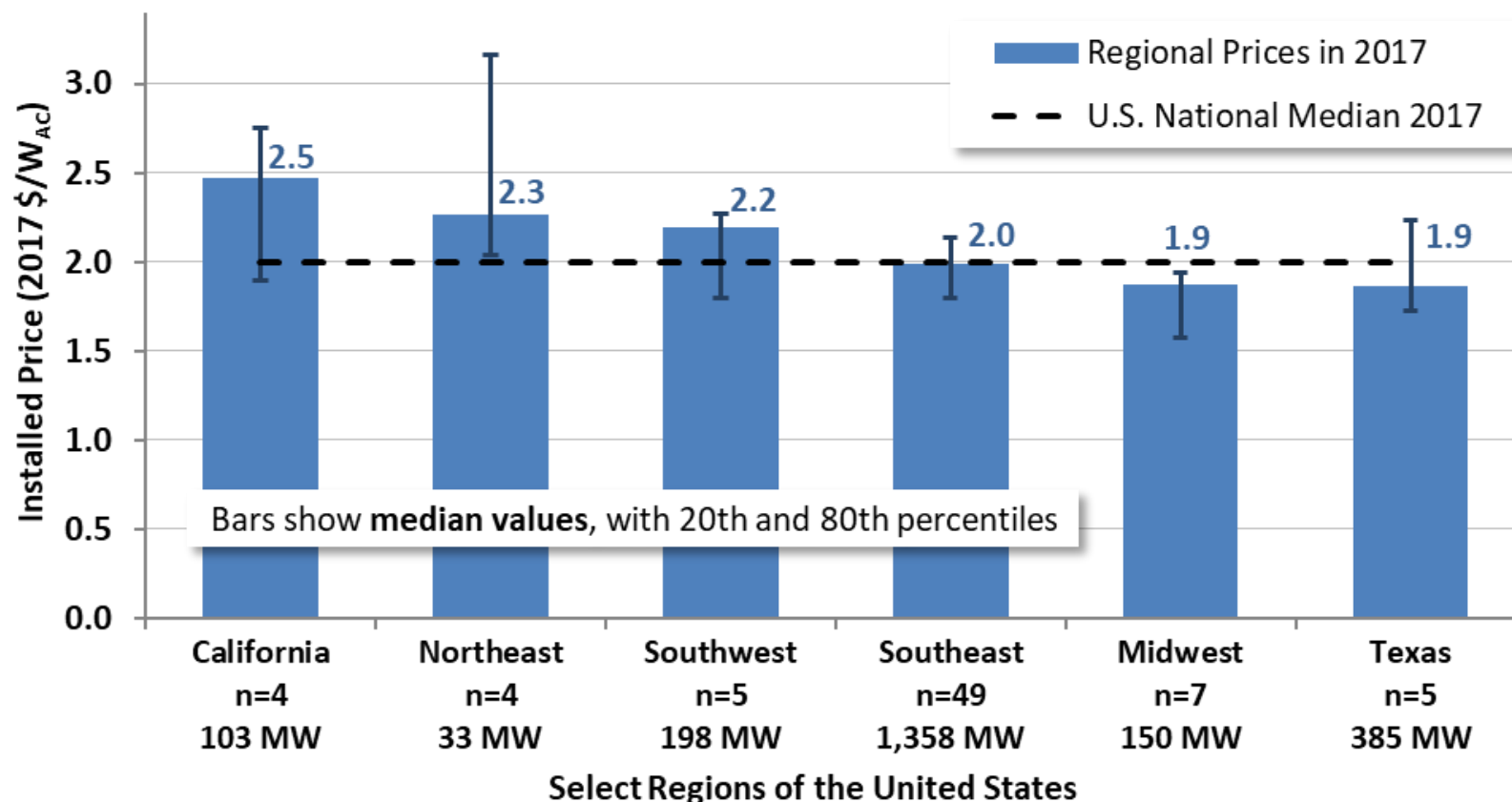
Median price for the first and second size bin (5-50MW) is slightly larger than for third and fourth size bin (50-200MW) - \$2.05/W_{AC} vs. \$1.90/W_{AC}.

In \$/W_{DC} terms cost decline is even more obvious over first three bins:

- \$1.57/W_{DC} for 5-20MW
- \$1.46/W_{DC} for 20-50MW
- \$1.35/W_{DC} for 50-100MW

Project prices vary by region, newcomers have lower prices

PV price sample for 2017: 76 projects totaling 2,303 MW_{AC}



Note: The regions are defined in the earlier slides with a map of the United States

Price differences could be driven in part by technology ubiquity (e.g., higher-priced tracking projects are more prevalent in the Southwest and California).

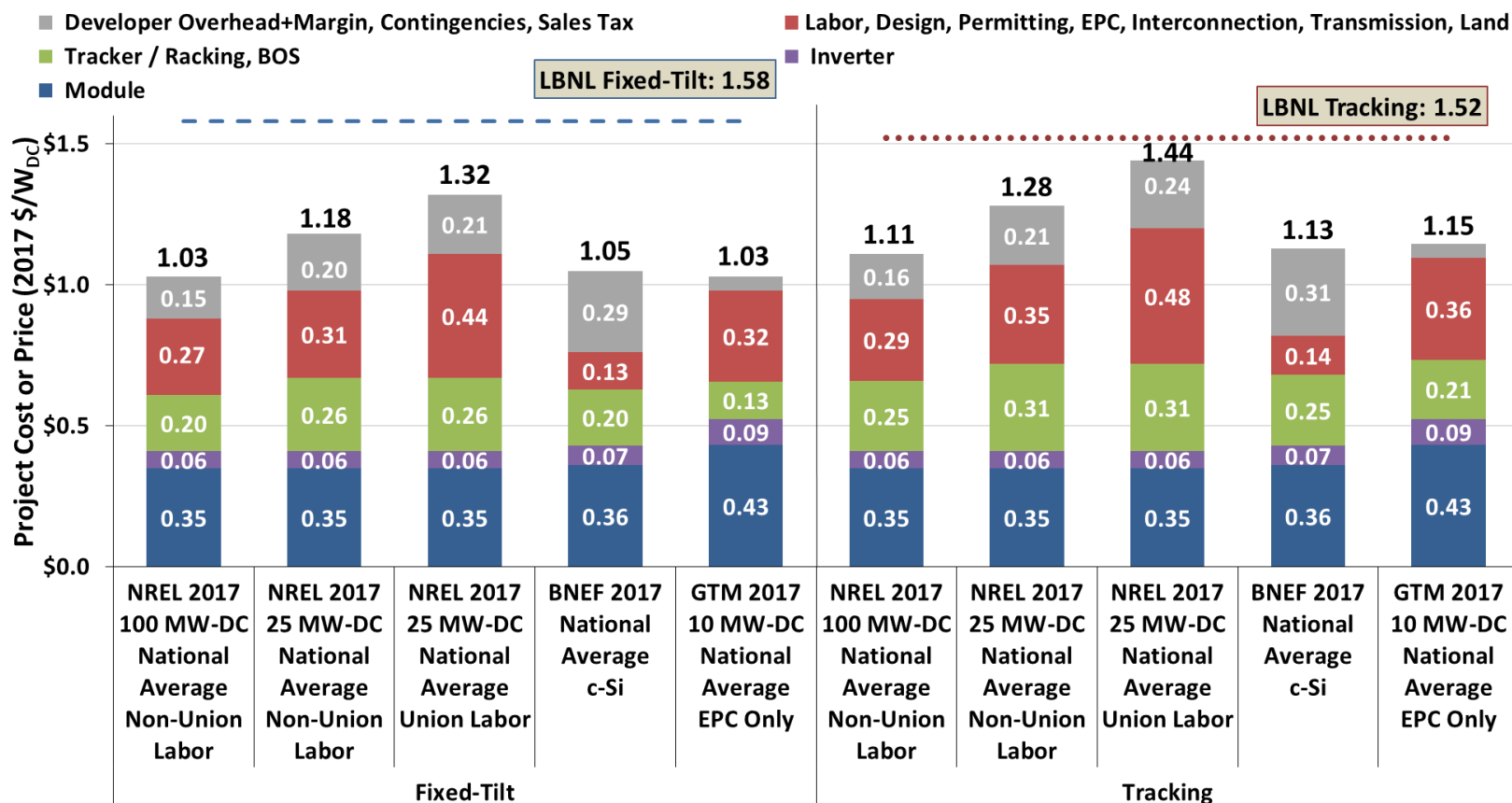
Other factors may include labor costs and share of union labor, land costs, terrain, soil conditions, snow and wind loads, and balance of supply and demand.

California, the Northeast, and the Southwest seem to be priced above the national median, while the Midwest and Texas appear to be lower priced.

Sample size outside of Southeast is very limited (Hawaii and Northwest are excluded due to few observations), so these rankings should be viewed with some caution.

Bottom-up models estimate lower prices than all-in cost reports

PV price sample for 2017: 76 projects totaling 2,303 MW_{AC}



LBNL's top-down estimates reflect a mix of union and non-union labor and span a wide range of project sizes and prices (\$0.6-\$3.3/W_{DC}).

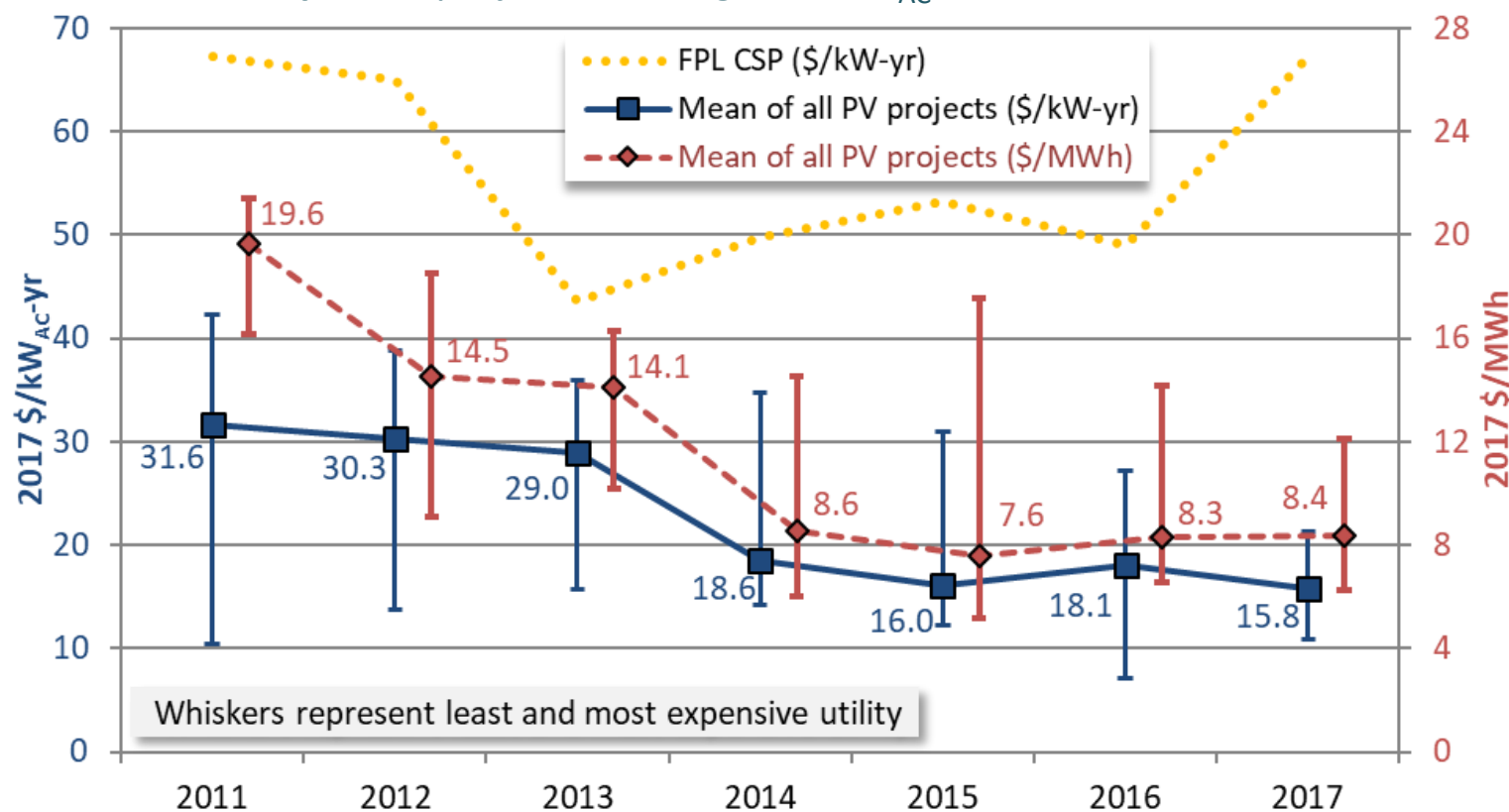
The median of our price sample is higher than other price estimates. While others continue to model a cost premium for trackers, our median reported prices indicate the reverse.

Some of the price delta may be due to differences in the defined system boundaries and time horizon (e.g. under construction vs. operation date). For example, GTM represents only turnkey EPC costs and excludes permitting, interconnection, and transmission costs, as well as developer overhead, fees, and profit margins.

Note: Prices are presented in \$/W_{DC} to enable comparison with estimates by NREL, BNEF, and GTM

Operation and Maintenance (O&M) Costs Narrow in Range

O&M Cost sample: 39 projects totaling 806 MW_{AC}



8 utilities report solar O&M costs for projects with ≥ 1 full operational year by 2017 and a mix of technologies (tracking vs. fixed tilt, module type).

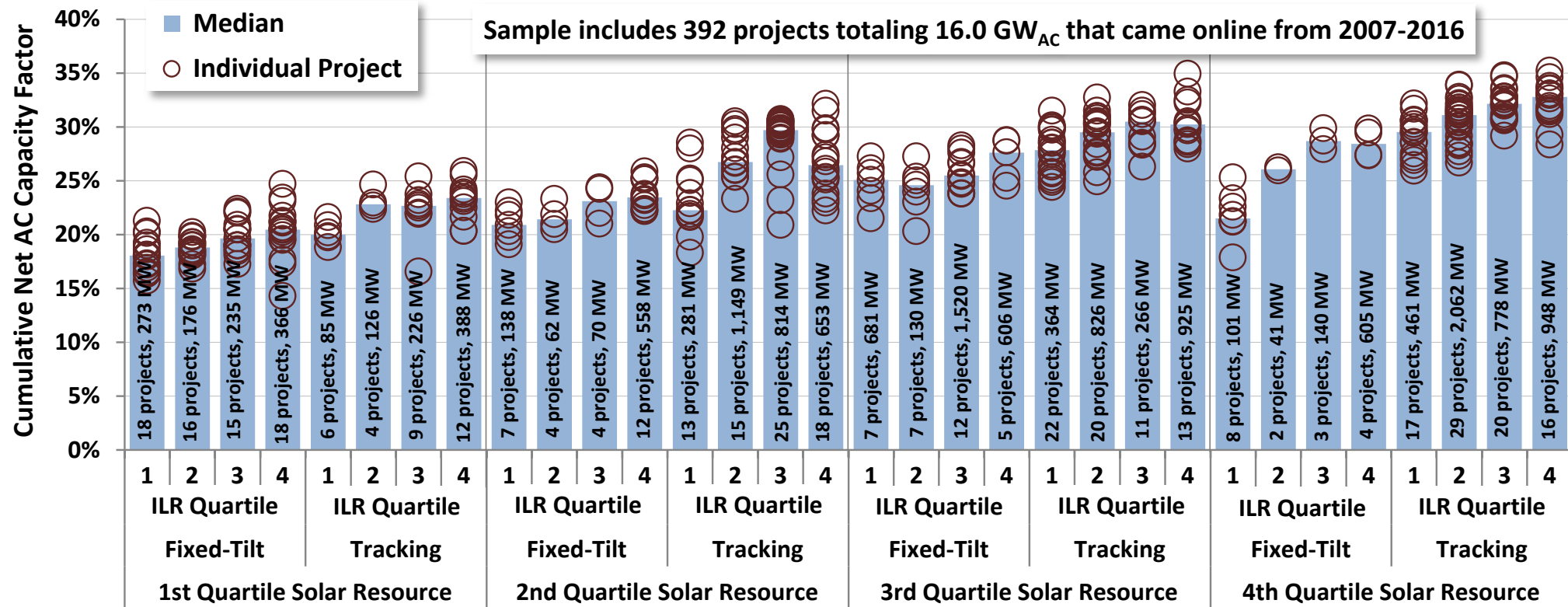
Average O&M costs for the cumulative set of PV plants have declined from about \$31/kW_{AC}-year (or \$20/MWh) in 2011 to about \$16/kW_{AC}-year (\$8.4/MWh) in 2017.

Overall cost range among utilities has decreased relative to earlier years, perhaps reflecting industry standardization or economies of scale.

Cost Scope (per guidelines for FERC Form 1):

- Includes supervision and engineering, maintenance, rents, and training
- Excludes payments for property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead

26.0% average sample-wide PV net capacity factor (cumulative), but with large project-level range from 14.3%-35.2%

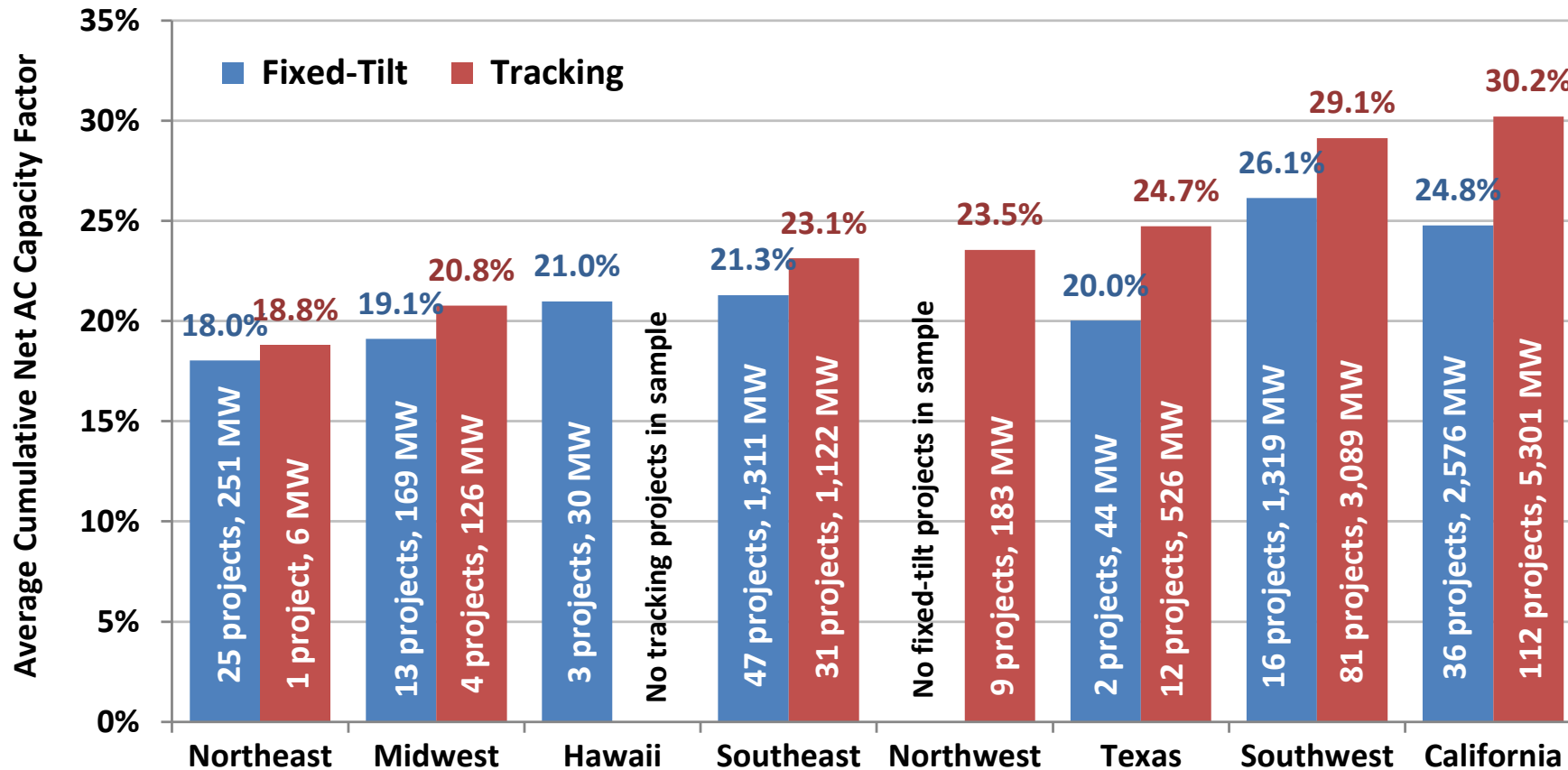


Project-level variation in PV capacity factor driven by:

- ❑ **Solar Resource (GHI):** Strongest solar resource quartile has a ~8 percentage point higher capacity factor than lowest resource quartile
- ❑ **Tracking:** Adds 3-5 percentage points to capacity factor on average, depending on solar resource quartile
- ❑ **Inverter Loading Ratio (ILR):** Highest ILR quartiles have on average ~3 percentage point higher capacity factors than lowest ILR quartiles

Tracking boosts net-capacity factors by up to 5% in high-insolation regions

PV Performance sample: 392 projects totaling 16,052 MW_{AC}



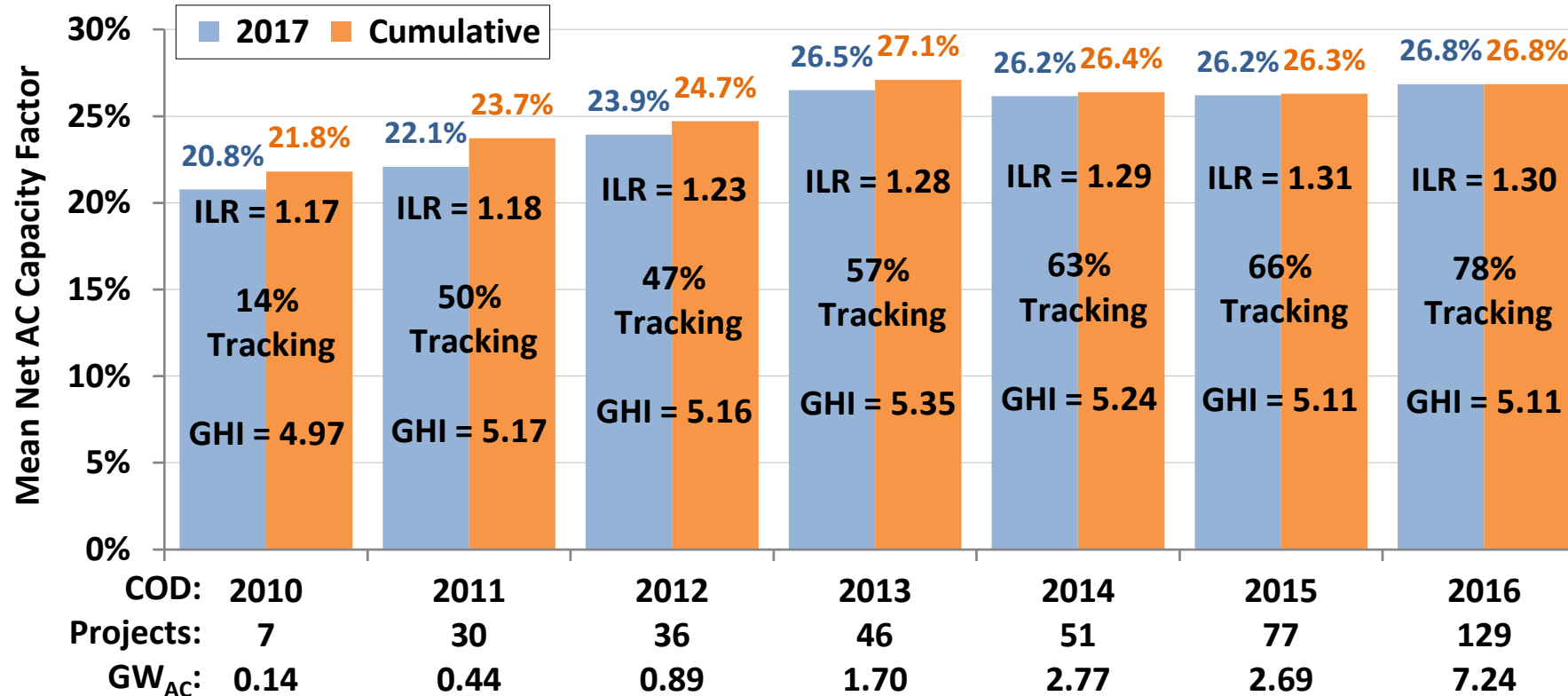
Not surprisingly, capacity factors are highest in California and the Southwest, and lowest in the Northeast and Midwest.

Although sample size is small in some regions, the greater benefit of tracking in the high-insolation regions is evident, as are the greater number of tracking projects in those regions.

Note: The regions are defined in the earlier slides with a map of the United States

Average capacity factors of younger projects remain stable despite build-out in less-sunny regions, thanks to increase in tracking

PV Performance sample: 392 projects totaling 16,052 MW_{AC}

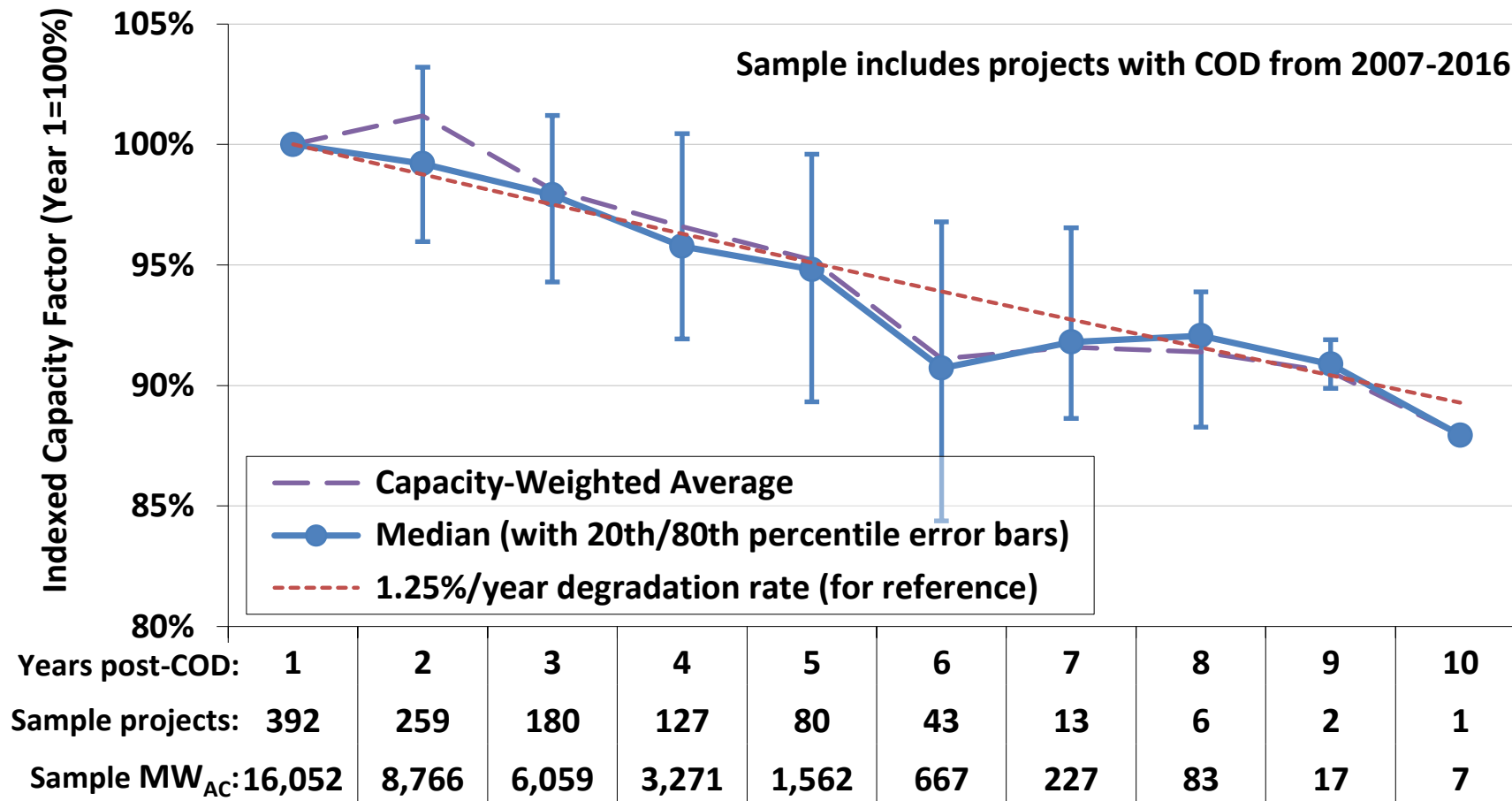


Average capacity factors increased from 2010- to 2013-vintage projects due to an increase in:

- ILR (from 1.17 to 1.28)
- tracking (from 14% to 57%)
- average site-level GHI (from 4.97 to 5.35)

But since 2013, average long-term site-level GHI has decreased (to 5.11) while tracking has increased (to 78%), with ILR roughly unchanged, leading to a general stagnation in average capacity factors among newer projects.

Performance degradation is evident, but is difficult to assess and attribute at the project level



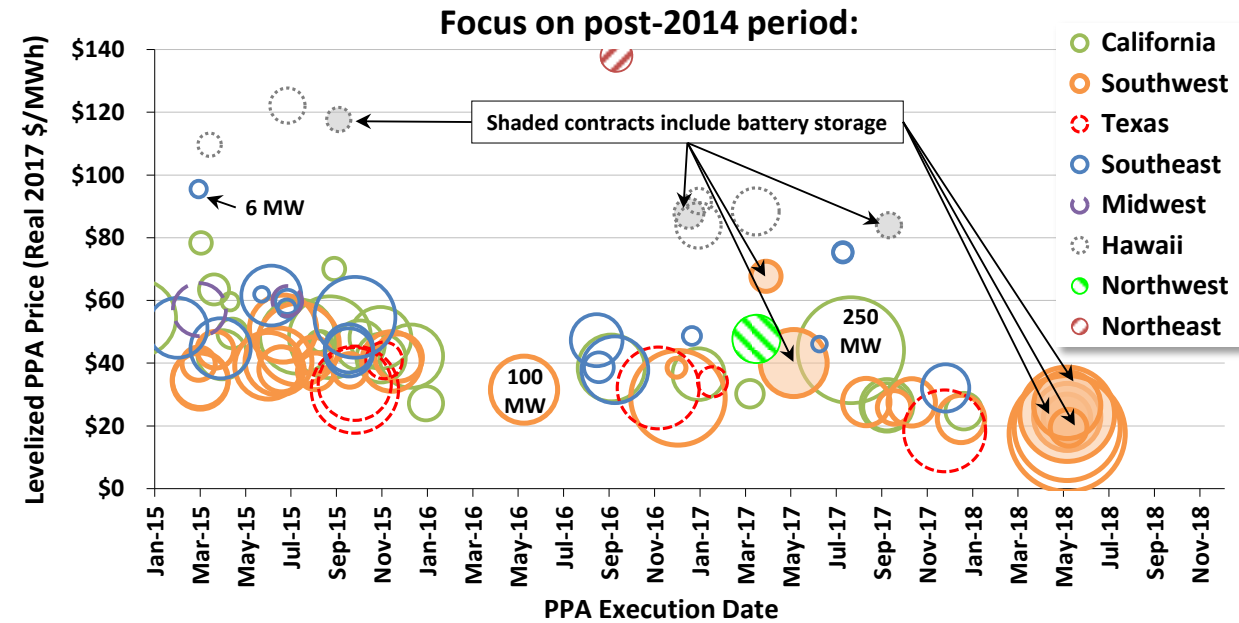
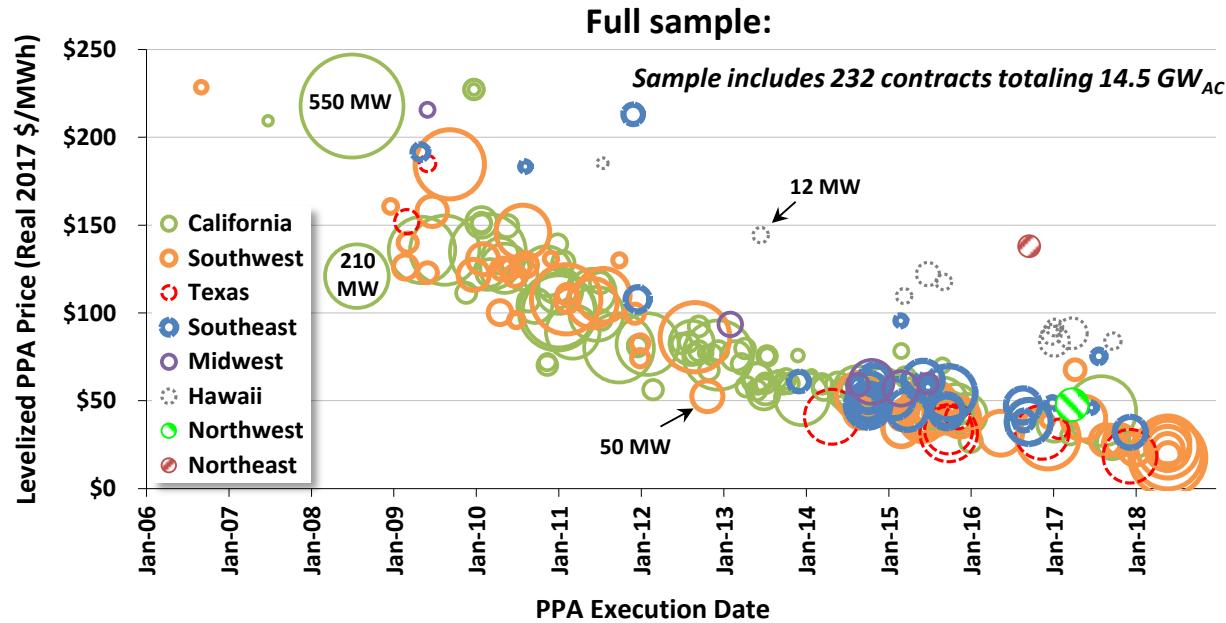
Fleet-wide degradation appears to be running at ~1.25%/year—i.e., higher than commonly assumed.

However, other important factors are not properly controlled for here:

- ❑ inter-year resource variability (e.g., several bad solar years in a row)
- ❑ curtailment (about 1.3% in 2017 in California – the largest market)
- ❑ an inconsistent sample (which drops off quickly) in each successive year

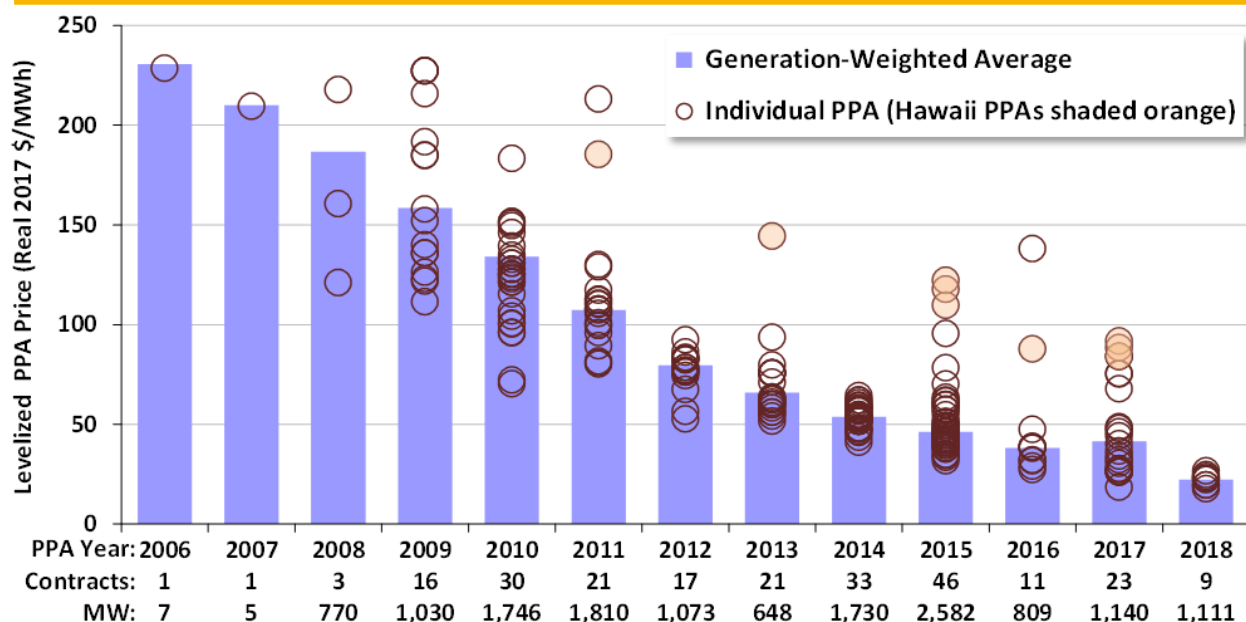
Graph shows indexed capacity factors in each full calendar year following COD.
No attempt has been made to correct for inter-year resource variation or other factors.

Combination of falling installed prices and better project performance enables lower PPA prices

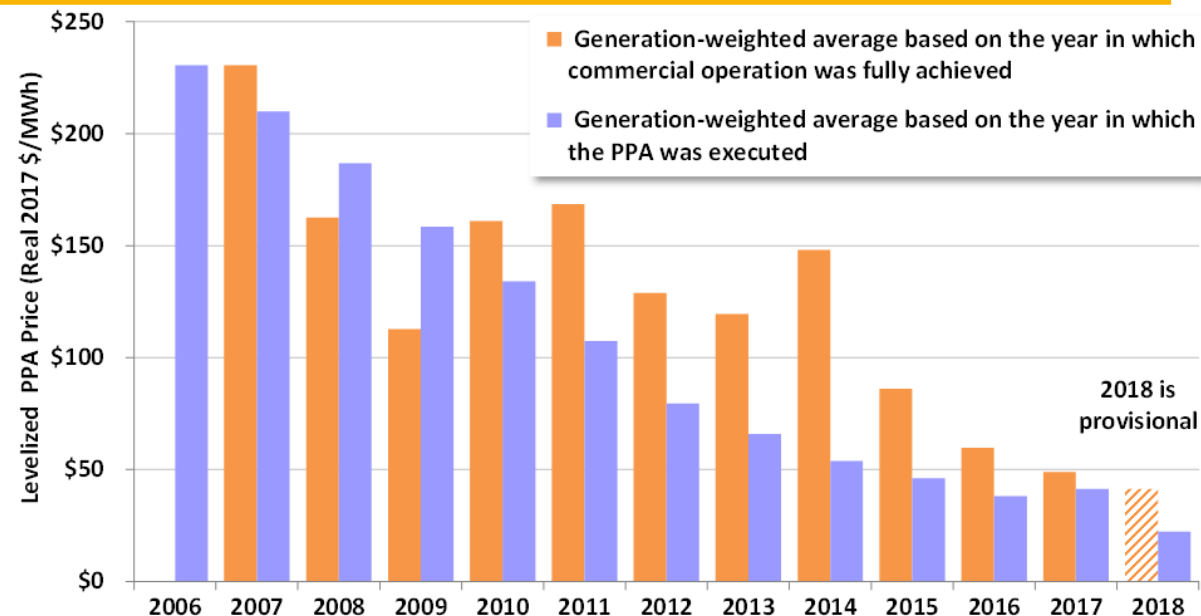


- Power Purchase Agreement (PPA) prices are **levelized** over the full term of each contract, after accounting for any escalation rates and/or time-of-delivery factors, and are shown in real 2017 dollars.
- Most recent PPAs are under \$40/MWh, with three recent PPAs in the Southwest under \$20/MWh.
- 8 PPAs featuring PV plus long-duration battery storage (4-5 hour, shaded in graphs) do not seem to be priced at a prohibitive premium to their PV-only counterparts.
- Hawaii projects show a consistent and significant premium of ~\$40/MWh over the mainland.
- Smaller projects (e.g., 20-50 MW) are seemingly no less competitive.
- >80% of the sample is currently operational.

On average, levelized PPA prices have fallen by ~85% since 2009

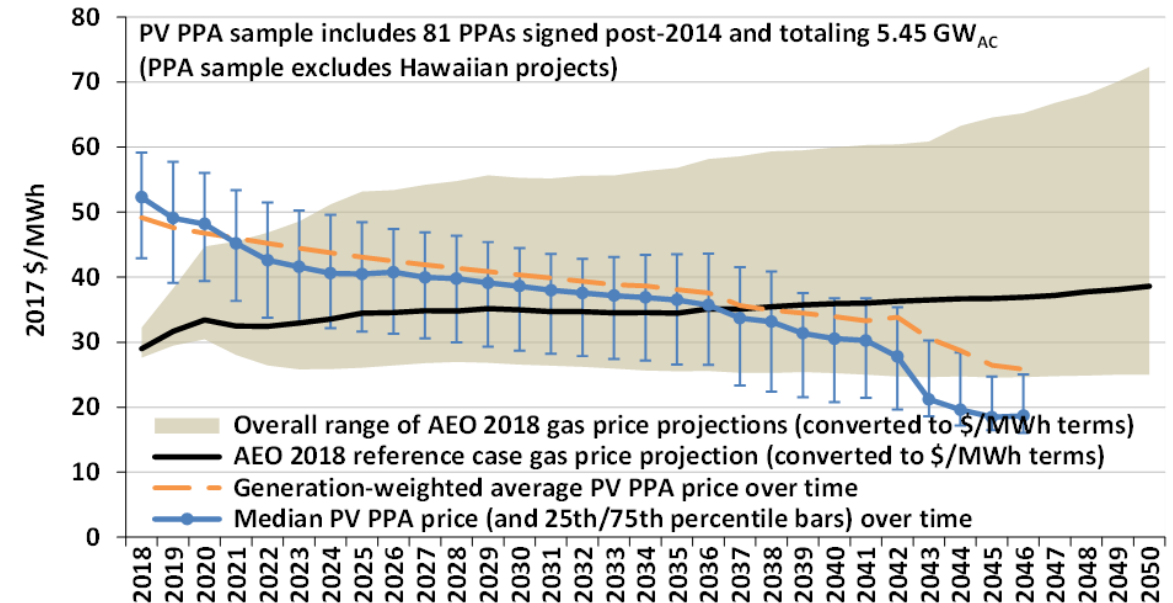
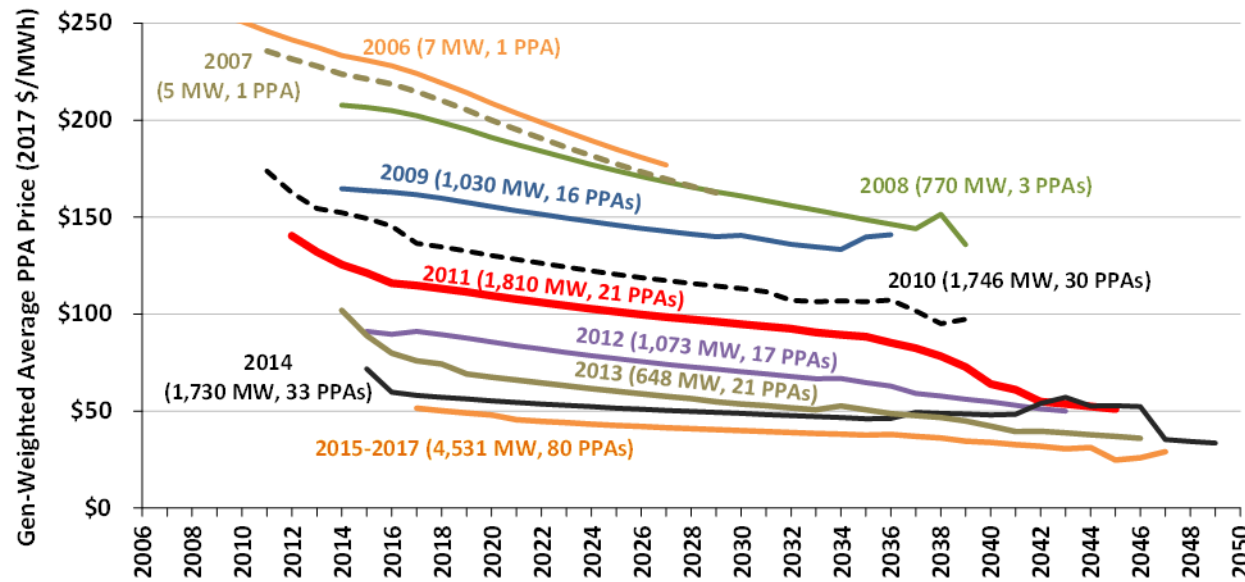


- Left figure presents the same data as previous slide, but in a different way: each circle is an individual contract, and the blue columns show the average levelized PPA price each year.
- Steady downward trend in the average PPA price over time slowed in 2017 (due to Hawaii, PV+storage), but has resumed so far in 2018.



- Price decline over time is more erratic when viewed by COD (orange bars in right graph) rather than by PPA execution date (blue bars).
- Though the average levelized price of PPAs signed in 2017 is ~\$40/MWh, the average levelized PPA price among projects that came online in 2017 is higher, at ~\$50/MWh.

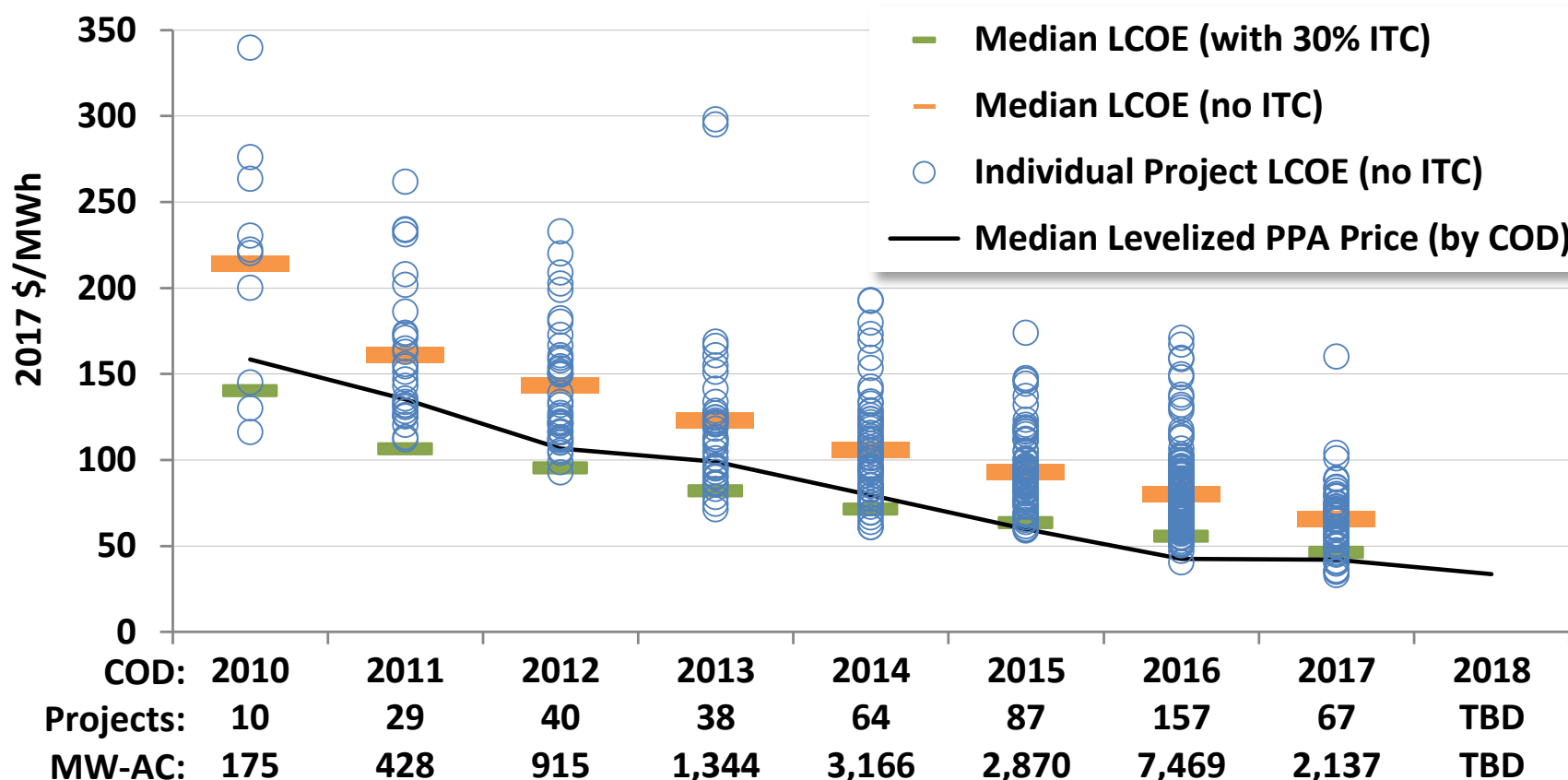
PV PPA prices generally decline over time in real dollar terms, in contrast to fuel cost projections



- Two-thirds of PV sample has flat annual PPA pricing (in nominal dollars), while the rest escalate at low rates. Thus, average PPA prices tend to **decline over time in real dollar terms** (left graph).
- Right graph compares recent PPA prices to range of gas price projections from AEO 2018. Although solar PPAs signed from 2015-2018 are priced higher than the cost of burning fuel in an **existing** combined-cycle natural gas unit (NGCC), over longer terms PV is potentially more competitive (depending on what happens to the price of natural gas), and can help protect against fuel price risk.
- PV PPAs are priced to recover *both* capital *and* other ongoing operational costs (for an NGCC, this would add another ~\$21-\$54/MWh to fuel costs). With declining battery costs, PV+storage is becoming a serious competitor to new gas-fired peaker plants (that have higher heat rates and thus higher fuel costs than those depicted in the right graph).

Levelized PPA prices track the LCOE of utility-scale PV

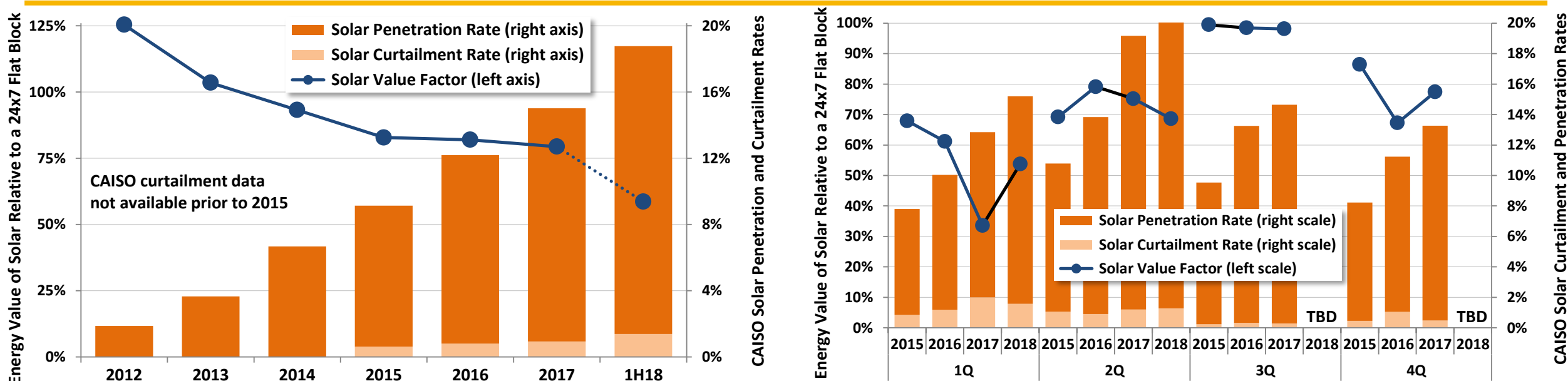
PV price sample: 492 projects totaling 18,504 MW_{AC}



Using empirical data from elsewhere in the report, along with a number of assumptions (e.g., about financing), we calculated project-level LCOEs for the entire sample of projects for which we have CapEx data.

Median estimates of LCOE track median PPA prices (shown here by COD rather than by execution date) reasonably well, suggesting a fairly competitive PPA market.

The value of solar tends to decline at higher penetration levels



- With increasing solar penetration in California, solar curtailment has increased and solar's wholesale energy value has declined.
- In 2012, when solar penetration was ~2%, solar earned 125% of the average wholesale power price (or \$38/MWh).
- In 2017, with solar penetration at ~15%, solar earned just 79% of the average wholesale power price (or \$25/MWh).
- The value decline is likely to continue in 2018 based on H1 earnings of 59% of the average wholesale power price (or \$17/MWh) – though H2 usually offers a rebound in value and earnings.
- Most other markets are not yet facing this value decline as solar penetration in 2017 was still low: ERCOT (\$34/MWh solar value = 127% of average wholesale price), SPP (\$29/MWh = 129%), PJM (\$26/MWh = 112%)

PV + storage projects proliferate

State	Project			Actual or Expected COD (PV/Battery)	Capacity (MW-AC)		Battery Storage		Battery:PV Capacity Ratio	% of PV MWh used to charge	Levelized PPA Price (2017 \$/MWh)
	Name	Sponsor	Offtaker		PV	Battery	Hours	MWh			
HI	Kapaia	Tesla	KIUC	Apr-17	13	13	4.0	52	100%	85%	117.7
FL	Babcock	NextEra	FPL	Dec-16/Mar-18	74.5	10	4.0	40	13%	9%	N/A
FL	Citrus	NextEra	FPL	Dec-16/Mar-18	74.5	4	4.0	16	5%	4%	N/A
AZ	Pinal Central	NextEra	SRP	Apr-18	20	10	4.0	40	50%	25%	67.7
HI	Lawai	AES	KIUC	Oct-18	20	20	5.0	100	100%	71%	87.8
TX	Castle Gap	Luminant	Luminant	Jun-18/Dec-18	180	10	4.2	42	6%	3%	N/A
HI	West Loch	HECO	HECO	Dec-18	20	20	4.0	80	100%	67%	N/A
MN	Ramsey/Athens	Engie/NextEra	Connexus	Dec-18	10	15	2.0	30	150%	57%	?
HI	Molokai	MNEP	MECO	Jun-19	4.88	3	5.0	15	61%	43%	140.0
HI	Kekaha	AES	KIUC	Sep-19	14	14	5.0	70	100%	77%	84.0
AZ	Wilmot	NextEra	TEP	Dec-19	100	30	4.0	120	30%	15%	40.0
CA	Desert Harvest II	EDF-RE	SCPPA	Dec-20	70	35	4.0	140	50%	24%	LMP (+\$15.25)
AZ	Redhawk(?)	First Solar	APS	Jun-21	65	50	2.7	135	77%	26%	?
NV	Battle Mountain	Cypress Creek	NV Energy	Jun-21	101	25	4.0	100	25%	12%	22.8
NV	Dodge Flat	NextEra	NV Energy	Dec-21	200	50	4.0	200	25%	13%	23.5
NV	Fish Springs Ranch	NextEra	NV Energy	Dec-21	100	25	4.0	100	25%	13%	26.4

The ratio of battery-to-PV capacity, and the % of PV output used to charge the battery, varies widely, reflecting specific circumstances of each project.

Though most projects in the table are greenfield projects, both Babcock and Citrus were retrofitted with batteries a year after coming online. A recent RFP from APS aims to do the same.

The incremental cost of storage (beyond that of PV alone) appears to be about half as much as it was just a year ago.

Different compensation models for PV + storage within PPAs:

- Bundle the storage compensation into the overall PPA price (earlier PV + storage projects).
- Compensate storage through fixed capacity payments (the recent NV Energy PPAs).
- No direct compensation, but given that PPA is priced at local nodal price, there is an incentive to store energy at low-priced hours and deliver during high-priced hours (Desert Harvest II).
- Only compensate for energy delivered in specific time window (3-8 PM, First Solar's APS project).

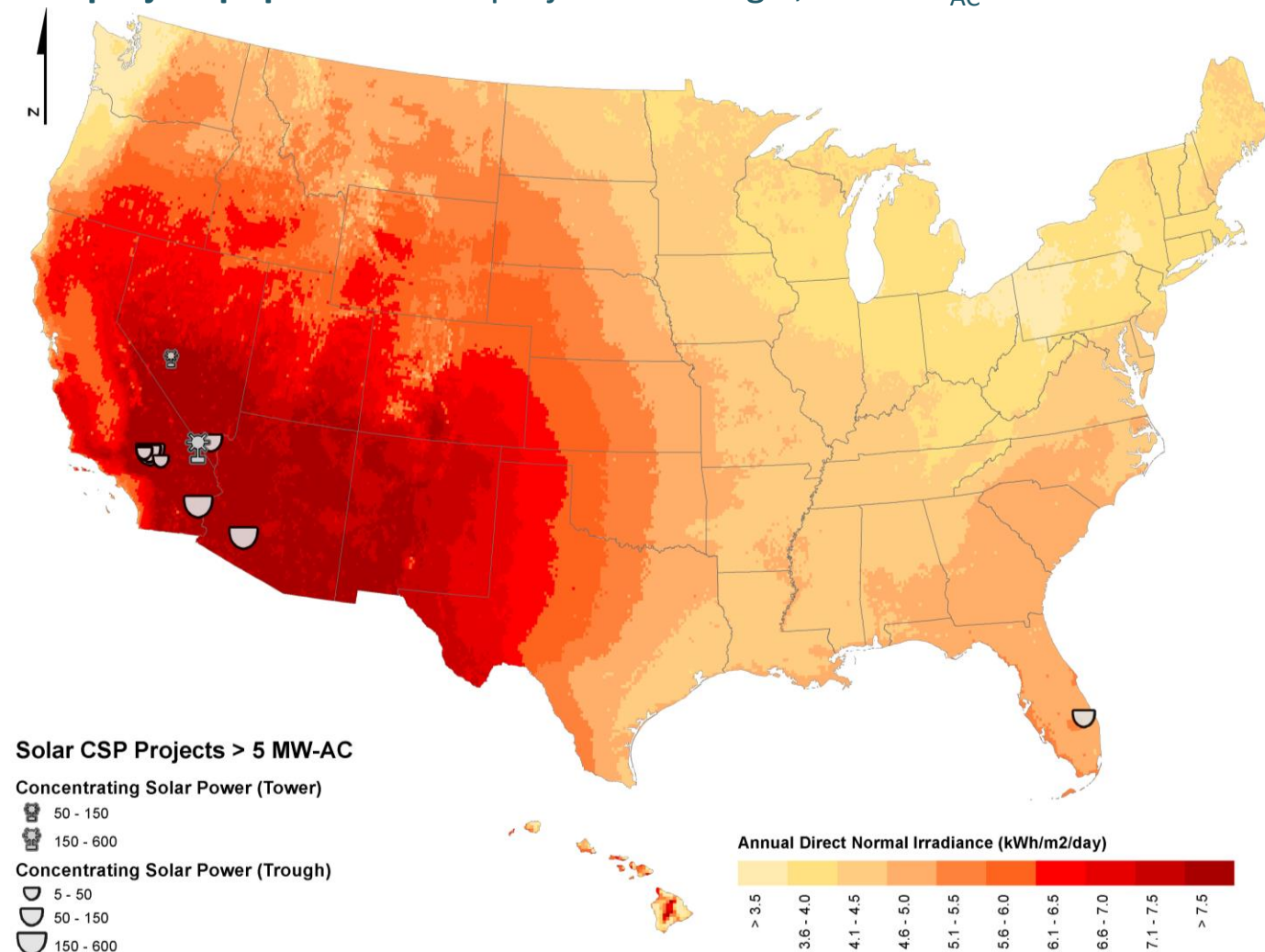
Utility-Scale Concentrating Solar Thermal Power (CSP)



Photo Credit: Solar Reserve: Crescent Dunes

Sample description of CSP projects

CSP project population: 16 projects totaling 1,781 MW_{AC}



After nearly 400 MW_{AC} built in the late-1980s (and early-1990s), no new CSP was built in the U.S. until 2007 (68 MW_{AC}), 2010 (75 MW_{AC}), and 2013-2015 (1,237 MW_{AC}).

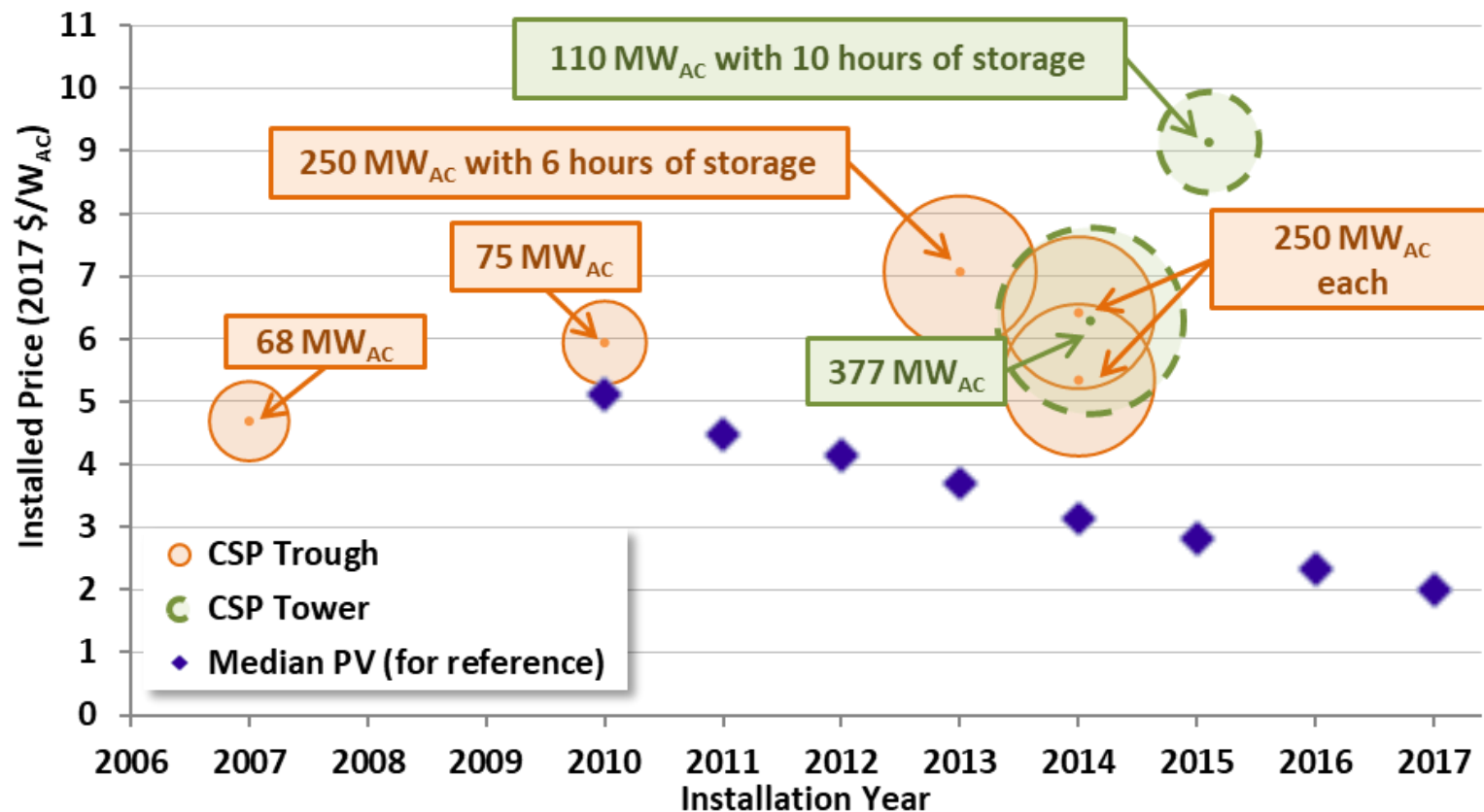
Prior to the large 2013-15 build-out, all utility-scale CSP projects in the U.S. used parabolic trough collectors.

The five 2013-2015 projects include

- 3 parabolic troughs (one with 6 hours of storage) totaling 750 MW_{AC} (net) and
- 2 “power tower” projects (one with 10 hours of storage) totaling 487 MW_{AC} (net).

Not much movement in the installed price of CSP

CSP price sample: 7 projects totaling 1,381 MW_{AC}

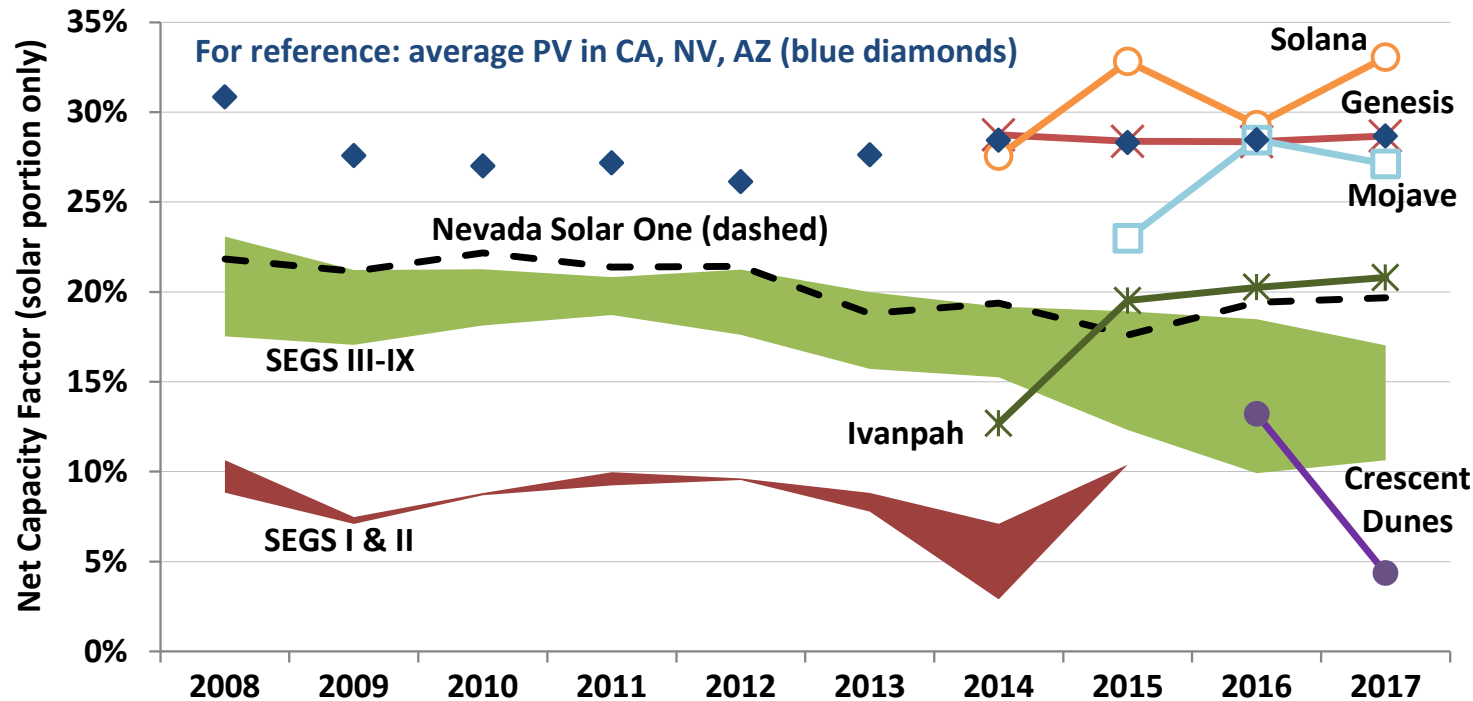


Small sample of 7 projects using different technologies makes it hard to identify trends. Newer projects (5 built in 2013-15) did not show cost declines, though some included storage or used new technology (power tower).

PV prices have continuously declined and are now far below the historical CSP prices. While international projects seem to be more competitive with PV, no new CSP projects are currently under active development in the U.S.

With the exception of 2 projects, newer CSP projects continue to underperform relative to long-term expectations

CSP performance sample: 13 projects totaling 1,654 MW_{AC}



The 2 “power tower” projects continued to perform below long-term expectations in 2017 (~27% for Ivanpah and ~50% for Crescent Dunes). Crescent Dunes was partially offline due to a molten salt container leak.

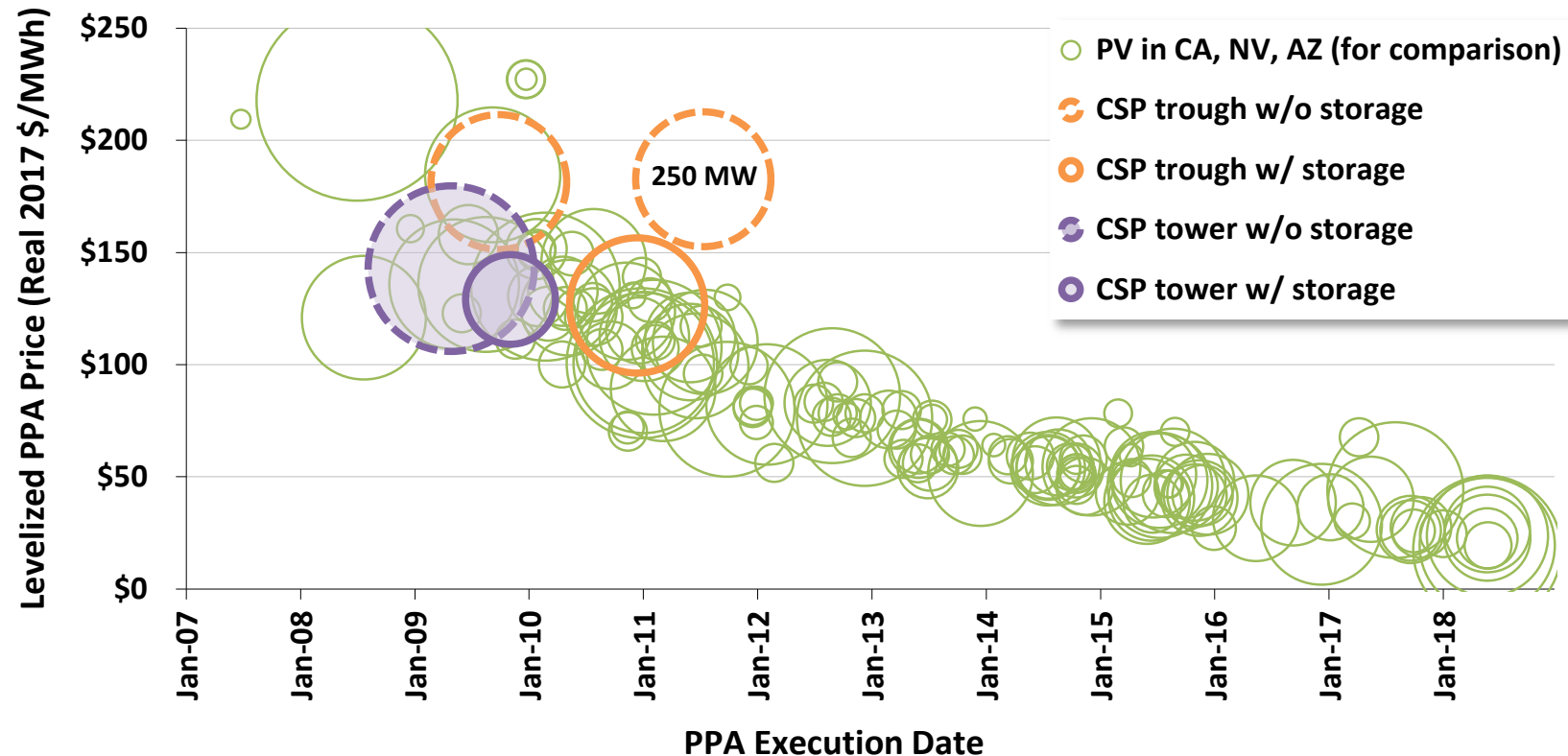
Solana (250 MW solar trough project with 6h thermal storage) was still below long-term expectations of >40% thanks to two transformer fires in July and August 2017.

The newer trough projects without storage (Genesis and Mojave) matched expectations and performed better than the eight older (25+ years) trough projects SEGS III-IX, and the 2007 Nevada Solar One trough project.

In 2016 and 2017, Solana, Genesis, and Mojave all matched or exceeded the average capacity factor among utility-scale PV projects across California, Nevada, and Arizona. All other CSP projects exhibited significantly lower capacity factors.

Though once competitive, CSP PPA prices have failed to keep pace with PV's PPA price decline

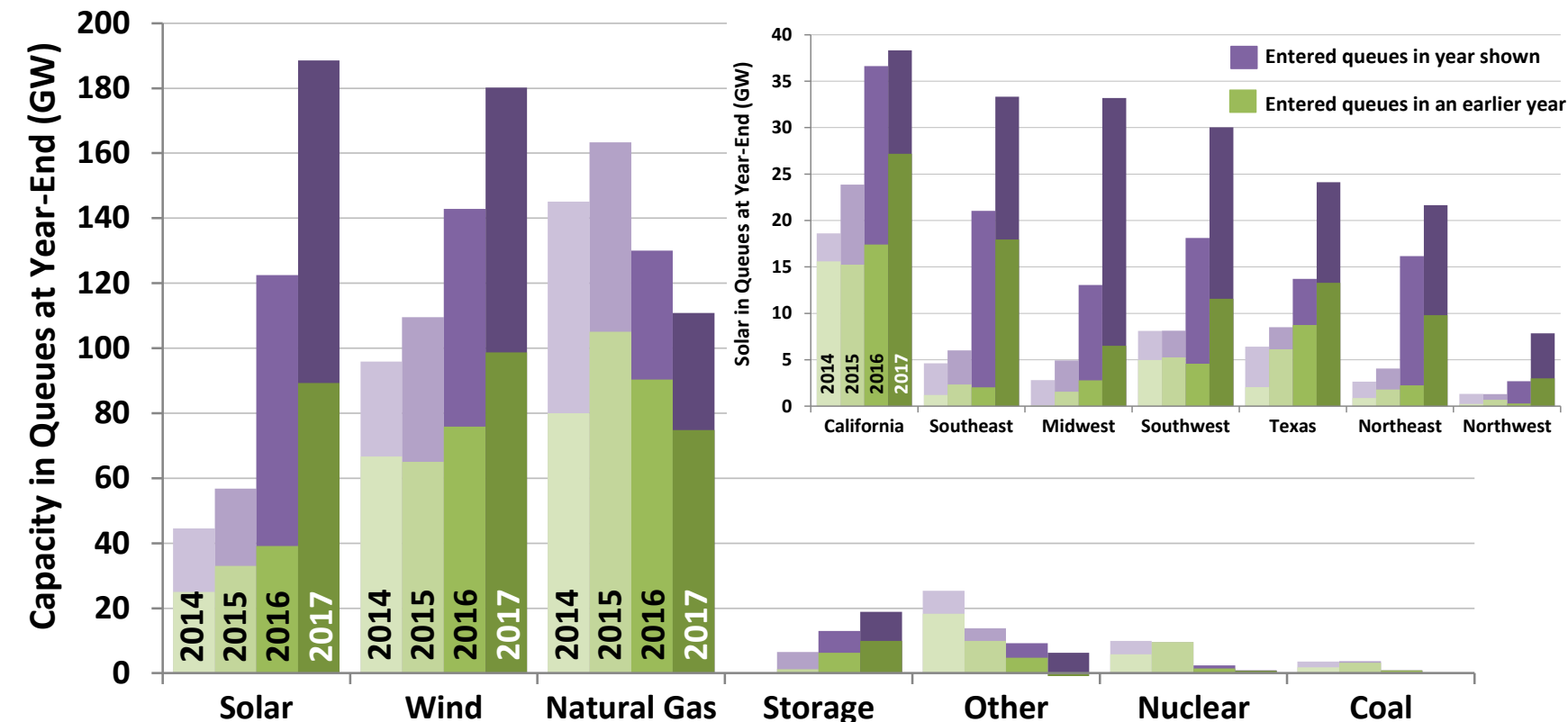
CSP PPA sample: 6 projects totaling 1,301 MW_{AC}



When PPAs for the most recent batch of CSP projects (with CODs of 2013-15) were signed back in 2009-2011, they were still mostly competitive with PV.

But CSP has not been able to keep pace with PV's price decline. Partly as a result, no new PPAs for CSP projects have been signed in the U.S. since 2011 – though the technology continues to advance overseas.

Looking ahead: Strong growth in the utility-scale solar pipeline



188.5 GW of solar was in the queues at the end of 2017, more than any other technology, and more than eight times the amount of installed capacity at the end of 2017.

99.2 GW of solar capacity entered the queues in 2017 – the most ever.

Very strong solar growth in all regions, with largest additions in the Midwest (where 27 GW were added in 2017 alone).

Storage capacity in the queues grew to 18.9 GW at the end of 2017, accounting for about 4% of total queue capacity and ranking a distant fourth behind solar, wind, and natural gas.

Graphs show solar and other capacity in 35 interconnection queues across the U.S.
Not all of these projects will ultimately be built!

Questions?

Download the full report, a data file, and this slide deck at:

<http://utilityscalesolar.lbl.gov>

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Utility-Scale Solar

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and PPA Pricing in the United States – 2018 Edition

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